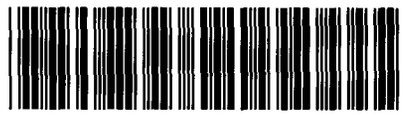

Control Number: 46831

Item Number: 681

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SOAH NO. 473-17-2686
PUC DOCKET NO. 46831

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| APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES | § § § | PUBLIC UTILITY COMMISSION OF TEXAS |

# CROSS-REBUTTAL TESTIMONY

# OF

# KEVIN C. HIGGINS

# FOR

# TEXAS INDUSTRIAL ENERGY CONSUMERS

**July 21, 2017**

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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 215 South State Street, Suite 200, 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. ARE YOU THE SAME KEVIN C. HIGGINS WHO FILED DIRECT TESTIMONY ON BEHALF OF TEXAS INDUSTRIAL ENERGY CONSUMERS ("TIEC") IN THIS DOCKET?**

A. Yes, I am.

**Q. WHAT IS THE PURPOSE OF YOUR CROSS-REBUTTAL TESTIMONY?**

A. My Cross-Rebuttal Testimony responds primarily to the direct testimony of the City of El Paso witness Clarence L. Johnson, Office of Public Utility Counsel ("OPUC") witness William Perea Marcus, and Commission Staff witness Grant Gervais regarding certain aspects of these parties' cost-of-service recommendations and/or revenue distribution recommendations.

**Q. PLEASE SUMMARIZE THE PRIMARY CONCLUSIONS OF YOUR CROSS-REBUTTAL TESTIMONY.**

A. I recommend that the load factor used for weighting average demand in the Average and Excess Four Coincident Peak ("A&E/4CP") calculation be based on:

1. The highest system annual peak, rather than the average of the four summer peaks recommended by Mr. Johnson.
2. Firm energy and demand, rather than loads inclusive of non-firm energy and demand utilized by Mr. Johnson.
3. Unadjusted energy and demand, rather than adjusted loads utilized by Mr. Gervais.

Further, I recommend that the Commission reject the following changes to EPE's class cost allocation proposed by other parties:

1. Increasing the proportion of production O&M expenses allocated based on energy as proposed by Mr. Johnson and Mr. Marcus;
2. Increasing the proportion of Palo Verde-related administrative and general ("A&G") expenses and payroll taxes allocated based on energy as proposed by Mr. Marcus;
3. Changing the allocation of the "general" portion of certain A&G expenses as proposed by Mr. Johnson;
4. Reducing CP demands for weather-sensitive classes used in the calculation of the A&E/4CP allocator for production demand costs and the 4CP allocator for transmission costs to reflect weather normalization, as proposed by Mr. Johnson;
5. Allocating the majority of Transportation equipment (Account 392) on Net Plant rather than Labor as included in the City of El Paso's cost-of-service model; and
6. Allocating a larger portion of labor costs for major account representatives to larger customers as proposed by Mr. Marcus, unless the Commission also adopts

an allocation of uncollectible expense consistent with the incurrence of actual net bad debt write-offs.

On the issue of revenue distribution, I recommend that:

1. The Commission reject Mr. Johnson's revenue distribution proposal. However, to the extent that gradualism is utilized, it should be reserved for those rate schedules that would experience rate increases of 30% or greater if class revenues were set equal to cost; and
2. The Commission reject Mr. Johnson's and Mr. Marcus's proposed dramatic increases to interruptible rates.

## II. CLASS COST ALLOCATION

**Q. TO WHICH PARTIES ARE YOU RESPONDING ON THE TOPIC OF CLASS COST ALLOCATION?**

A. I am responding primarily to the direct testimony of the City of El Paso witness Mr. Johnson, OPUC witness Mr. Marcus, and Commission Staff witness Mr. Gervais. Because of the large number of class cost allocation issues addressed by other parties, I have organized my response on an issue-by-issue basis.

### Load Factor Used for Weighting Average Demand

**Q. WHY IS LOAD FACTOR RELEVANT FOR ALLOCATING CLASS COSTS IN THIS CASE?**

A. Similar to other Texas utilities, EPE uses the A&E/4CP method for allocating production costs. As discussed in my direct testimony,[1] an essential step when using this method is to weight the average demand (or energy) component of this allocator by the system load

[1] Direct Testimony of Kevin C. Higgins, pp. 20-25.

factor. While there is no controversy that "load factor" must be used for this weighting, there is disagreement among the parties as to how the load factor should be calculated for this purpose.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CALCULATION OF LOAD FACTOR USED IN WEIGHTING AVERAGE DEMAND IN THIS CASE?**

A. I recommend using a system load factor that is based on:

1. The system annual peak demand;
2. Firm energy and demand; and
3. Unadjusted energy and demand.

I will address each of these topics in greater detail below.

*a. Number of Peaks Included in Load Factor*

**Q. WHAT DO OTHER PARTIES RECOMMEND REGARDING THE APPROPRIATE NUMBER OF PEAKS TO INCLUDE IN THE LOAD FACTOR CALCULATION?**

A. The use of a system load factor measured using the single highest system annual peak is also supported in the direct testimonies of Commission Staff witness Mr. Gervais,[2] U.S. Department of Defense and All Other Federal Executive Agencies witness Laurie A. Tomczyk,[3] and the University of Texas at El Paso witness Kit Pevoto.[4]

However, Mr. Johnson proposes to utilize a load factor based on the average of the four monthly peaks rather than the annual system peak.

**Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S RECOMMENDATION?**

[2] Direct Testimony of Grant Gervais, pp. 10-11.
[3] Direct Testimony of Laurie A. Tomczyk, pp. 8-10.
[4] Direct Testimony of Kit Pevoto, pp. 9-10.

A. The use of the average of four monthly peaks for determining system load factor is inappropriate. This issue was fully litigated in the 2015 Southwestern Public Service Company ("SPS") base rate case, Docket No. 43695, and the Commission properly rejected the identical proposal put forth by Mr. Johnson in this case.[5]

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 kWh usage was consumed at a 100% load factor for the entire year. Consistent with this premise, 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 annual system peak demand is consistent with the discussion of the Average and Excess Demand method in the NARUC Manual,[6] as

[5] Docket No. 43695, Order at Finding of Fact 251A (Dec. 18, 2015).
[6] National Association of Regulatory Utility Commissioners *Electric Utility Cost Allocation Manual* (January 1992) p. 49.

well as the approach EPE uses in assessing its load and resource balance to calculate its planning reserve margin.[7]

Calculating load factor using the annual system peak demand also comports with the definition of "Load factor" in §25.5 of the Electric Substantive Rules, defined as: "[t]he ratio of average load to peak load during a specific period of time, expressed as a percent."[8] In this case, load factor is properly calculated using the peak load experienced during the twelve months ended September 30, 2016.

*b. Inclusion of Non-Firm Load in Load Factor*

**Q. DO YOU AGREE WITH MR. JOHNSON'S RELIANCE ON DATA IN SCHEDULE O-1.6 FOR CALCULATING THE LOAD FACTOR?**

A. No. Schedule O-1.6 includes non-firm load. As non-firm load is not included in the allocation of production plant, it should be excluded from the load factor used in allocating production plant. My calculation of system load factor excludes non-firm load. Appropriately, EPE also excludes non-firm load from its calculation.

*c. Adjusted Versus Unadjusted Loads for Load Factor*

**Q. WHILE YOU AND MR. GERVAIS AGREE THAT THE LOAD FACTOR SHOULD BE MEASURED USING THE SINGLE HIGHEST FIRM COINCIDENT PEAK, DO YOU USE AN IDENTICAL LOAD FACTOR?**

A. No. My recommended load factor for class cost of service purposes differs from that of Mr. Gervais for several reasons. First, Mr. Gervais utilizes adjusted demand and energy

[7] See EPE's Response to RFI Staff 6-3, Staff 6-3 Attachment 1.
[8] Excerpted from Electric Substantive Rules §25.5--6, General Provision 64.

data rather than unadjusted data. Next, Mr. Gervais further adjusts this load data to reflect the output from the solar facilities that EPE directly assigns to New Mexico or Texas, excluding Newman 10.[9] Lastly, Mr. Gervais adds 19,693 MWhs to system energy, intended to reverse EPE's reduction for energy efficiency, which increases Mr. Gervais's calculated load factor, since no similar adjustment is made for demand. [10]

**Q. DO YOU AGREE THAT THE LOAD FACTOR SHOULD BE BASED ON ADJUSTED DATA?**

A. No. I recommend that the load factor be calculated using unadjusted demand and energy data, which is consistent with the Commission's decision in Docket No. 43695.[11] I utilized the data provided in EPE's response to RFI TIEC 10-1, TIEC 10-01_Attachment 02, which reflects unadjusted demand and energy,[12] as well as the differentiation of 115 kV and 69 kV loss factors as approved in the Commission's order in Docket No. 46308.[13]

**Q. DO YOU AGREE THAT THE LOADS USED TO CALCULATE THE LOAD FACTOR FOR CLASS COST-OF-SERVICE PURPOSES SHOULD BE REDUCED FOR SOLAR PLANT OUTPUT?**

A. No. An adjustment to reflect solar plant output is not necessary for the load factor used in the A&E/4CP allocator for Texas class cost-of-service purposes. The output from directly-assigned solar generation has no bearing on the allocation of costs *among* Texas

[9] See 46831 - Staff's Model of EPEC's Class Cost of Service (Errata), "Alloc Calc (PGG-6)" tab.
[10] In Staff's original direct filing, Mr. Gervais made an apparently inadvertent error in adjusting New Mexico's energy for the output from New Mexico solar facilities, resulting in a higher load factor. See 46831 - Attachments PGG 2, 3, 4, 6, and 7_AIS Final, "Alloc Calc (PGG-6)" tab. This error was corrected in Mr. Gervais's errata filed July 17, 2017.
[11] See Docket No. 43695 Proposal for Decision, page 228, which indicates that SPS's load factor should be based on adjusted demand, and confirms that unadjusted demand was utilized by SWEPCO in Docket No. 40043.
[12] This data reflects EPE's errata filed May 19th.
[13] Docket No. 46308, Order at Ordering Paragraph 2 (Jun. 29, 2017).

rate classes, so no load adjustments for solar plant output are required when determining Texas class cost of service allocators.

**Q. IS IT APPROPRIATE TO INCREASE THE ENERGY USED IN THE LOAD FACTOR TO REVERSE EPE'S ENERGY EFFICIENCY ADJUSTMENT?**

A. No. I recommend utilizing unadjusted loads, which are unaffected by EPE's energy efficiency adjustment. Since EPE's energy efficiency adjustment is not included in these loads, they will be unchanged whether EPE's energy efficiency adjustment is approved or rejected.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE APPROPRIATE LOAD FACTOR TO USE IN THE A&E/4CP CALCULATION FOR CLASS COST OF SERVICE PURPOSES.**

A. My recommended load factor is calculated using the highest annual system coincident peak and unadjusted firm loads, and is presented in Exhibit KCH-8 of my direct testimony. As discussed above, my recommendation is consistent with Commission precedent in cases in which the proper calculation of system load factor was litigated. In this case, the correct load factor to use for class cost of service purposes is 50.23%, rather than 50.75% as utilized by Mr. Gervais,[14] or 53.50% as utilized by Mr. Johnson.[15]

**Proportion of Production Expenses Allocated Based on Energy**

**Q. WHAT RECOMMENDATIONS MADE BY OTHER PARTIES REGARDING THE PROPORTION OF PRODUCTION EXPENSES ALLOCATED BASED ON ENERGY DO YOU ADDRESS?**

[14] 46831 - Staff's Model of EPEC's Class Cost of Service (Errata), "Alloc Calc (PGG-6)."
[15] Direct Testimony of Clarence L. Johnson, p. 18.

A. Both Mr. Johnson and Mr. Marcus make several recommendations that have the effect of increasing the proportion of production O&M expenses allocated on the basis of energy. In addition, Mr. Marcus proposes to increase the proportion of certain Palo Verde A&G expenses and Palo Verde payroll tax expense allocated based on energy.[16]

**Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THESE VARIOUS PROPOSALS BY MR. JOHNSON AND MR. MARCUS TO ALLOCATE A GREATER PROPORTION OF EPE'S PRODUCTION EXPENSE BASED ON ENERGY?**

A. Yes. It is important to recognize at the outset that EPE already allocates a significant proportion of its non-fuel production O&M expense on the basis of energy, much of which reasonably could be allocated instead on the basis of A&E/4CP.[17] For example, EPE allocates the majority of Accounts 506 (Miscellaneous steam power expenses), 553 (Other Maintenance of generating and electric plant), and 554 (Maintenance of miscellaneous other power generation plant) based on energy, although the NARUC Manual classifies these accounts as 100% demand-related. [18]

In my direct testimony, I opted not to challenge these classification decisions by EPE, concluding that EPE had conducted a careful account-by-account treatment that reflected reasonable judgment regarding energy/demand weightings for these expenses and had reached an appropriate balance. As the Commission considers each of the piecemeal arguments by certain parties to alter these weightings further in the direction of

[16] Direct Testimony of William Perea Marcus, 30-31. In addition to increasing the energy-allocated portion of these expenses, Mr. Marcus's allocation proposal would include an A&E/12CP component.
[17] In total, EPE allocates 32% of its Texas-allocated non-fuel production O&M expenses based on energy, and 68% based on demand. In this context, "demand" includes both A&E/4CP and A&E/12CP. Derived from EPE Regulatory Case Working Model - As Filed - Dkt 46831, "Rate Class Allocation" tab.
[18] National Association of Regulatory Utility Commissioners *Electric Utility Cost Allocation Manual* (January 1992), pp. 36, 38.

energy, I encourage the Commission to recognize that the Company's energy/demand weightings for production O&M expense already provide a considerable energy component.

**Q. TURNING TO THE PROPOSALS BY MR. JOHNSON, WHAT HAS HE SPECIFICALLY RECOMMENDED ON THIS ISSUE?**

A. Mr. Johnson recommends changing the classification of Accounts 500 (Steam Operation supervision and engineering) and 510 (Steam Maintenance supervision and engineering) to 59% energy/ 41% demand, whereas EPE classifies these accounts as 100% demand and allocates them using A&E/4CP. Mr. Johnson's classification is based on the proportion that Steam Generation payroll expense comprises of total Non-Fuel Steam expense.[19]

Mr. Johnson recommends that Accounts 512 through 514 (Boiler Maintenance, Electric Plant Maintenance, and Miscellaneous Steam Maintenance) be classified as 100% energy, whereas EPE classifies the labor-related portion of these accounts as demand-related and the non-labor portion as energy-related.

Mr. Johnson also proposes that Accounts 517 (Nuclear Operation supervision and engineering), 519 (Nuclear Coolants), 520 (Nuclear Steam Expense), and 523 (Nuclear Electric Expense) be classified as 35% energy/ 65% demand, rather than 100% demand as EPE proposes. Mr. Johnson's proposal is based on the proportion that Palo Verde Operations payroll comprises of total non-fuel Palo Verde Operations expense.[20]

Mr. Johnson contends that his proposed classification revisions are consistent with the NARUC Manual.

[19] Direct Testimony of Clarence L. Johnson, p. 22.
[20] *Id.*, p. 23.

**Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S RECOMMENDATIONS?**

A. As I indicated above, the Company's classification of production O&M expenses strikes a reasonable balance between energy and demand. While the NARUC Manual provides guidance on the typical classification of production O&M expenses, judgment should be applied when determining the energy or demand-related character of the costs in each account. Moreover, the A&E/4CP allocator used by EPE already includes an average demand (or energy) component.

Further, the Commission approved an allocation of Account 514 based on A&E/4CP in the recently litigated rate cases of SPS,[21] Southwestern Electric Power Company ("SWEPCO"), [22] and Entergy Texas, Inc. ("ETI")[23] (Dockets 43695, 40443, and 39896, respectively).

Accounts 517, 519, 520, and 523 are a pass-through of Palo Verde costs from Arizona Public Service Company ("APS") and EPE's classification reflects the fixed nature of the costs that are being passed through. I recommend that these accounts continue to be allocated based on A&E/4CP.

In sum, the Commission should approve the allocation of Accounts 500, 510, 512, 513, 514, 517, 519, 520, and 523 as presented in EPE's direct case.

**Q. TURNING TO THE SPECIFIC PROPOSALS BY MR. MARCUS, WHAT HAS HE PROPOSED REGARDING THE ALLOCATION OF PRODUCTION EXPENSES?**

[21] 43695 - Final Order Class Cost of Service Study v2.
[22] 41892 Comm NR 40443 Swepco CCOS Model Schedules WP 9 23 13.
[23] Comm Number Run 39896 ETI COS 8.28.12 SENT –REDACTED.

A. Like Mr. Johnson, Mr. Marcus proposes that Accounts 512 through 514 be allocated based on energy.[24] Mr. Marcus also recommends that the allocation of Account 510 include a greater energy component, based on the allocation of expenses in Accounts 511 through 514. Including the impact of Mr. Marcus's recommended treatment of Accounts 512 though 514 as entirely energy-related, Mr. Marcus would allocate 6% of Account 510 on demand and 94% on energy.[25]

Similarly, Mr. Marcus recommends that Account 528 (Nuclear Maintenance supervision and engineering) be allocated based on the overall allocation of expenses in nuclear maintenance Accounts 529 through 532.[26] This would result in 8% of Account 528 being allocated on demand and 92% on energy.[27]

Regarding Palo Verde production-related A&G expenses, Mr. Marcus recommends an increased energy allocation for Accounts 925, 926, and 930.2 (injuries and damages [largely workers' compensation], pensions and benefits, and miscellaneous general expenses, respectively). Mr. Marcus utilizes the overall allocation of Palo Verde expenses in Accounts 517 through 532 and 556 (except fuel in Account 518 and water and coolants in Account 519) to allocate Accounts 925, 926, and 930.2. This proposed allocation would result in 29% of Accounts 925, 926, and 930.2 being allocated based on energy, and 71% on demand. [28] Mr. Marcus proposes the same allocation approach for Palo Verde-related payroll tax expense. [29]

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[24] Direct Testimony of William Perea Marcus, p. 5.
[25] In this context, "demand" refers to A&E/4CP. Derived from EPE Regulatory Case Working Model - OPUC Modifications – Confidential.
[26] Direct Testimony of William Perea Marcus, p. 18.
[27] In this context, "demand" refers to A&E/4CP. Derived from EPE Regulatory Case Working Model - OPUC Modifications – Confidential.
[28] In this context, "demand" refers to A&E/4CP and A&E/12CP. Derived from EPE Regulatory Case Working Model - OPUC Modifications – Confidential.
[29] Direct Testimony of William Perea Marcus, p. 30-31.

**Q. WHAT IS YOUR RESPONSE TO MR. MARCUS'S RECOMMENDATIONS?**

A. With regard to Accounts 510, 512, 513, and 514, I recommend that EPE's proposed treatment of these accounts in its direct filing be approved. As explained above, EPE's classification of production O&M expenses strikes a reasonable balance between energy and demand.

The Palo Verde A&G expenses allocated to EPE by APS in Accounts 925, 926, and 930.2, and Palo Verde payroll tax expense are reasonably treated as a fixed cost, as they are more closely related to EPE's capacity share of Palo Verde than variable energy throughput. I recommend continued utilization of the A&E/4CP method for allocation of these expenses.

**Allocation of "General" A&G Expenses**

**Q. WHAT CHANGES TO THE ALLOCATION OF A&G EXPENSES ARE BEING PROPOSED BY MR. JOHNSON?**

A. Mr. Johnson proposes to allocate the "general" portion of Accounts 920, 921, 923, and 930.2 (A&G Salaries, Office Supplies, Outside Services, and Miscellaneous general expenses) based on Net Plant, rather than the Labor allocator utilized by EPE for the majority of these expenses. [30] According to Mr. Johnson, the "general" portion of these expenses represents costs that cannot be attributed to a particular utility function. Mr. Johnson argues that EPE's utilization of the Labor allocator understates the role of the production function in EPE's operations, since Palo Verde labor costs are largely excluded from EPE's Labor allocator.

**Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?**

[30] Direct Testimony of Clarence L. Johnson, pp. 24-29.

A. I disagree with Mr. Johnson's recommendation. EPE excludes Palo Verde costs from its Labor allocator because APS manages these costs on behalf of the co-owners of that plant. By changing the allocator for certain A&G expenses to Net Plant, which includes Palo Verde, Mr. Johnson's adjustment would ascribe 28% of the costs of these A&G expenses[31] to a plant that EPE does not operate, and of which EPE owns only a 15.8% share. This change unduly distorts cost responsibility for these expenses.

**Weather Normalization 4CP Adjustment**

**Q. PLEASE DESCRIBE MR. JOHNSON'S ADJUSTMENT TO 4CP DEMANDS FOR WEATHER NORMALIZATION.**

A. Mr. Johnson contends that an adjustment to reduce the 4CP demands of weather-sensitive classes is appropriate, since EPE reduced the kWhs for these classes to reflect weather normalization. Mr. Johnson reduces the 4CP demands utilized in the 4CP and A&E/4CP allocators for the Residential, Small General Service, Municipal Pumping Service, Irrigation Service, General Service, Military Reservation Service, and City and County Service classes. His adjustment is based on EPE's net reduction to kWh for weather normalization in the summer months for each applicable class and each class's summer load factor.[32]

**Q. DO YOU BELIEVE THAT MR. JOHNSON'S ADJUSTMENT IS APPROPRIATE?**

A. No. As a threshold matter, weather normalizing CP demands used for cost allocation can be problematic because a utility's system is designed with consideration of contingencies

[31] Based on the proportion that Nuclear Production comprises of the "NETPLT" allocator, per EPE Regulatory Case Working Model - As Filed - Dkt 46831, "Dynamic Allocators" tab.
[32] Direct Testimony of Clarence L. Johnson, pp. 19-21.

such as higher-than-expected demand. A utility must be prepared to meet firm peak loads, even in unusually hot weather. The additional contribution to the system's CP by certain classes due to hotter-than-normal weather is relevant to the appropriate allocation of fixed costs.

Nevertheless, it appears that the CP demands used by EPE already include the impact of weather normalization. In response to RFI FMI 2-1, EPE explains, "EPE uses the estimated class load and coincidence factors with the adjusted energy that has been annualized for customers and adjusted for energy efficiency and weather normalized to estimate monthly, maximum and coincident demand by rate class and jurisdiction." [33]

Therefore, to further reduce CP demands for weather-sensitive classes, as proposed by Mr. Johnson, would overstate the impact of weather normalization. This would result in fewer demand-related costs being allocated to weather-sensitive classes than appropriate under the principle of cost-causation. I recommend that Mr. Johnson's adjustment be rejected.

**Transportation Equipment**

**Q. ARE YOU CONCERNED WITH ANY OTHER COST ALLOCATION CHANGES IN THE CITY OF EL PASO'S ANALYSIS?**

A. Yes. The City of El Paso's cost-of-service model changes the allocation of the majority of Account 392 (Transportation equipment) from Labor to Net Plant.[34] I recommend that this change be rejected because it would unduly distort cost responsibility for this plant. EPE has separately booked a portion of Account 392 related to Palo Verde, which

[33] From EPE's response to RFI FMI 2-1(2).
[34] EPE Regulatory Case Working Model - Dkt 46831 (CEP), "Rate Class Allocation" tab.

is allocated based on A&E/4CP, and the City of El Paso's model does not change this allocation. Therefore, it is particularly inappropriate to increase the weight of Palo Verde costs in the allocation of Account 392.

Moreover, this change should be rejected because it is entirely unsupported in the direct testimony submitted by the City of El Paso.

**Major Account Representatives**

**Q. WHAT CHANGE IS BEING PROPOSED REGARDING THE ALLOCATION OF THE COST ASSOCIATED WITH MAJOR ACCOUNT REPRESENTATIVES?**

A. Mr. Marcus recommends that a greater portion of the labor cost for major account representatives be allocated to larger customers. Specifically, Mr. Marcus recommends that 28% of the cost for major account representatives be allocated to Rate Nos. 15, 25, 26, 30, and 31 based on customer count, while allocating the remainder to other non-residential classes based on energy.[35] EPE allocates the entire major account representatives cost ($377,935 in Account 903 plus $70,423 for pensions and benefits) to non-residential customer classes based on customer count.[36]

**Q. WHAT IS YOUR RESPONSE TO MR. MARCUS'S PROPOSAL?**

A. If this change in the allocation of major account representative expenses is adopted, I recommend that it be adopted in tandem with the allocation of uncollectible expense to classes in a manner consistent with the actual incurrence of net bad debt write-offs, as Ms. Pevoto,[37] Freeport-McMoRan, Inc. witness Charles S. Griffey,[38] and I recommend in

[35] Direct Testimony of William Perea Marcus, pp. 28-30. Mr. Marcus's allocation excludes lighting classes (Rate Nos. 7, 8, 9, and 28) and Water Heating.
[36] EPE's allocation excludes Rate No. 28 and Water Heating.
[37] Direct Testimony of Kit Pevoto, pp. 12-15.

our direct testimonies. Both of these changes involve a more granular assignment of specific costs among customer classes.

## III. REVENUE DISTRIBUTION

**Q. IN YOUR DIRECT TESTIMONY YOU SUPPORTED EPE'S PROPOSAL TO SET EACH CLASS'S REVENUE REQUIREMENT EQUAL TO ITS COST OF SERVICE. HAVE ANY PARTIES FILED TESTIMONY IN OPPOSITION TO THAT APPROACH?**

A. Yes. Mr. Johnson proposes that each class move only 50% of the way toward cost of service, and that no class be permitted a rate decrease, if EPE's overall revenue requirement is increased in this case. Mr. Johnson also asserts that industrial customer classes are riskier to serve than classes such as residential.

**Q. IS MR. JOHNSON'S RECOMMENDATION CONSISTENT WITH THE COMMISSION'S GUIDANCE REGARDING ITS REVENUE DISTRIBUTION POLICIES?**

A. No. The issue of gradualism was one of the most contested issues in the 2015 SPS base rate case, Docket No. 43695. On December 18, 2015, the Commission issued its order in that case, which 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

[38] Direct Testimony of Charles S. Griffey, pp. 15-22.

> 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 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.[39]

As noted in the Order, the SPS case resulted in at least one class receiving a rate increase of 24.28%, while several other classes received rate decreases.[40]

**Q. WHAT WAS THE GRADUALISM RECOMMENDATION IN THE PROPOSAL FOR DECISION IN THE SPS CASE?**

A. The ALJs had recommended moving classes toward cost of service, and in the event of an overall rate increase, provided that no class received an increase of more than 200% of the system average base rate increase and no class receive a rate decrease.[41] However, the Commission rejected that limitation and directed that rates be moved all of the way to cost, without gradualism constraints.

**Q. HAS THE COMMISSION CONSIDERED GRADUALISM CONSTRAINTS IN OTHER RECENT CASES INVOLVING INTEGRATED INVESTOR-OWNED UTILITIES?**

A. Yes, in addition to the SPS case, the Commission decided contested cases for two other major integrated utilities (SWEPCO and ETI) in recent years. In each case, the Commission rejected the position of the parties that recommended gradualism and directed that rates be set at cost. In the SPS case mentioned above, the range of base rate

[39] Docket No. 43695 Order at 10 (Dec. 18, 2015). (Emphasis added. Citations omitted.)
[40] Docket No. 43695, Order at Attachment C (Dec. 18, 2015).
[41] Docket 43695, PFD, pp. 271, 283.

changes was from an 8.52% decrease to a 24.28% increase.[42] In the case of SWEPCO, the range was from a 17.05% decrease to a 29.20% increase,[43] and in ETI, the range was from a 7.89% decrease to a 10.43% increase.[44] In each case the Commission set rates for each class at cost and rejected the application of gradualism proposals.

**Q. DO YOU HAVE ANY OBSERVATIONS ABOUT MR. JOHNSON'S CONTENTIONS THAT INDUSTRIAL AND MANUFACTURING CUSTOMERS ARE INHERENTLY RISKIER TO SERVE?**

A. Yes, I disagree with him. Mr. Johnson has cited no evidence that EPE's industrial and manufacturing customers are riskier to serve than residential customers or any other type of customers. Further, Mr. Johnson ignores the benefits large industrial customers provide for system efficiency and stability, including that they typically have a high load factor and are often less sensitive to weather than residential customers.

Moreover, the Commission has previously rejected arguments like the one Mr. Johnson raises here. In Docket No. 5560,[45] the Cities' witness, Daniel J. Lawton, argued that industrial customers should pay higher rates because they are riskier to serve, and that issue was fully litigated. The Hearing Examiner rejected the Cities' proposal and included the following discussion in the Examiner's Report:

> TIEC Exhibit 9 is an article by Drs. Fairchild and Avera summarizing the findings of a major research project analyzing the customer class risk argument. That analysis demonstrated that there is no basis for setting a higher rate of return for any particular customer class on the basis of risk.

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[42] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order at Attachment C (Dec. 18, 2015).
[43] Docket No. 40443, Order on Re-Hearing, Attachment C, p. 1 (Feb. 5, 2014).
[44] Docket No. 39896, Comm Number Run 39896 ETI COS 8.28.12 SENT -REDACTED.xlsx.
[45] *Application of Gulf States Utilities Company for a Rate Increase,* Docket No. 5560, Revised Examiners' Report at 124 (Jul. 3, 1984), adopted by Final Order (Jul. 13, 1984).

> There are a number of characteristics of industrial rates which minimize the risk of revenue losses associated with industrial customers. These include ratchets, which protect the utility from a sudden loss of revenue, and separately-stated demand and energy charges, which also help protect revenue stability. Neither of these elements are present in residential rates. (TIEC Exhibit 3 (Pollock), pg. 11.) In addition, the high load factor of industrial customers provides the system with a number of benefits such as economies of scale and fuel savings which Mr. Lawton apparently overlooked. (Tr. pg.244 line 16 through pg. 248 line 5 (Edwards cross).)
>
> The overwhelming weight of the evidence in the record establishes that there is no additional risk associated with serving industrial customers. If anything, industrial customers are less risky to serve than other customer classes. Further, the existence of high load factor customers on GSU's system enables that system to operate more efficiently. There is no support for the addition of any penalty or surcharge to the rates of industrial customer on the basis of perceived risk.

The Commission adopted the Examiner's Report on this point, including the finding of fact that "[t]he preponderance of credible evidence in the record clearly established that there is no additional risk associated with serving industrial customers."[46] I am not aware of any Commission decisions since Docket No. 5560 in which the Commission departed from this analysis.

As with the Cities' witness in Docket No. 5560, Mr. Johnson has not provided credible evidence in this case that industrial customers are riskier to serve. His recommendation that residential and local government classes should be expected to produce a lower relative rate of return than industrial classes should be rejected.

**Q. PLEASE SUMMARIZE YOUR CROSS-REBUTTAL TESTIMONY REGARDING REVENUE DISTRIBUTION.**

[46] Revised Examiners' Report at 147, Finding of Fact 77.

A. As I recommended in my direct testimony, EPE's proposal to move all Texas rate classes to full cost of service should be adopted, at the revenue requirement ultimately approved in this proceeding and incorporating my recommended changes to jurisdictional and class cost allocation.

I recommend that the Commission reject Mr. Johnson's revenue distribution as fundamentally inconsistent with the Commission's recently-affirmed policy of setting rates at cost without mitigation for class rate impacts up to at least 29%. To the extent that gradualism is utilized, it should be reserved for those rate schedules that would experience rate increases of 30% or greater if class revenues were set equal to cost.

## IV. INTERRUPTIBLE RATES

**Q. WHAT DO MR. JOHNSON AND MR. MARCUS PROPOSE REGARDING INTERRUPTIBLE RATES?**

A. Both Mr. Johnson and Mr. Marcus propose dramatic increases to Interruptible Service (Rate No. 38). Mr. Johnson proposes an increase to interruptible rates of $2.54 million,[47] or 66%, while Mr. Marcus proposes an increase of $2.34 million,[48] or 61%. Mr. Johnson argues that, at a minimum, interruptible rates should recover the full transmission cost of approximately $5.00 per kW in order to avoid subsidized delivery rates.

**Q. DO YOU AGREE WITH MR. JOHNSON THAT THE DELIVERY COST FOR TRANSMISSION VOLTAGE INTERRUPTIBLE CUSTOMERS IS APPROXIMATELY $5.00 PER KW?**

[47] Direct Testimony of Clarence L. Johnson, p. 50.
[48] Direct Testimony of William Perea Marcus, p. 14. Percentage change based on current interruptible base revenue of $3,873,965, per Schedule Q-07.00.

A. No. Mr. Johnson argues that the production component of the Rate 25 demand charge is approximately 73%, so the transmission voltage interruptible demand charge should be set at approximately $5.00 per kW in order to recover delivery charges. However, Mr. Johnson's calculation of a 73% production component appears to include primary and secondary distribution costs, which do not apply to transmission voltage customers. Based on EPE's Direct Schedule P-6.01, the Demand Transmission unit cost for Rate 25 is $1.97 per kW, which is comparable to EPE's proposed Rate 38 transmission voltage demand charge of $1.93 per kW, and is less than the current rate of $2.22 per kW. Based on Schedule P-6.01, the Demand Production cost for transmission voltage Rate 25 customers comprises 89% of total demand costs, not 73%.[49]

I supplied a workpaper with my direct filing named Unit Costs - TIEC COS Model, which represents unit costs based on my recommended cost-of-service model, at EPE's proposed revenue requirement. According to that workpaper, the Demand Transmission unit cost for Rate 25 is $1.92 per kW, approximately equal to EPE's proposed Rate 38 transmission voltage demand charge of $1.93 per kW.[50]

**Q. WHAT IS YOUR RECOMMENDATION REGARDING INTERRUPTIBLE RATES?**

A. I support EPE's proposal in its direct filing to essentially maintain interruptible revenue at its current level. While Mr. Johnson and Mr. Marcus propose to assign greater charges for capacity to interruptible customers, their proposals are misplaced because they

[49] Based on P-06.01-UNIT COST ANALYSIS- PROPOSED RATE SCHEDULES PROPOSED RATE CLASSES, Rate 25 Production Demand costs are $16.487/kW and Transmission Demand costs are $1.970/kW. These unit costs are based on EPE's proposed revenue requirement and cost-of-service study.

[50] The transmission unit costs in the Unit Costs - TIEC COS Model workpaper include the cost of the 69 kV transmission system, which I recommend not be allocated to customers served at 115 kV. I estimate that the unit cost of the 69 kV system is approximately $0.25 per kW for Rate 25 customers, based on the estimated proportion that 69 kV costs comprise of total transmission cost from EPE's supplemental response to RFI TIEC 8-6.

overlook the fact that EPE does not plan its system to provide capacity to interruptible load, but rather uses interruptible load as a planning resource to reduce the Company's system capacity requirements, thereby providing a valuable resource for the benefit of all customers. This is evident by examining EPE's load and resources table included in its 2015 Integrated Resource Plan, which shows a 52 MW reduction in system demand peak attributable to interruptible load.[51] This translates into a reduction in generation planning requirements of 60 MW when 15% planning reserves are considered. While the capacity payments that interruptible customers make provide revenues that benefit the rest of the system, there is little cause to increase capacity charges to customers for whom system capacity is not planned in the first place. EPE's proposed rates provide appropriate compensation to interruptible customers for this resource. Additional capacity charges for these customers are unwarranted.

**Q. WHAT DOES MR. MARCUS PROPOSE REGARDING THE TREATMENT OF INTERRUPTIBLE LOADS FOR COST OF SERVICE PURPOSES?**

A. Mr. Marcus proposes that the Commission require EPE to include interruptible loads as if they are firm in the cost-of-service study in the next rate case. He also recommends that the interruptible credit be further reduced in the next rate case, and be treated as a production demand-related expense and allocated to all non-interruptible customers.[52]

**Q. WHAT IS YOUR RESPONSE TO MR. MARCUS'S COST OF SERVICE PROPOSAL?**

A. I recommend that interruptible loads continue to be excluded from the cost-of-service study. The nature of interruptible service is fundamentally different from, and of a lesser

[51] Integrated Resource Plan of El Paso Electric Company for the Period 2015-2034, July 6, 2015, p. 58.
[52] Direct Testimony of William Perea Marcus, pp. 14-15.

quality than, firm service. It is not appropriate to allocate demand-related costs to interruptible customers on the same basis as firm customers by including interruptible loads in the cost-of-service study as if they are firm. I also oppose Mr. Marcus's recommendation that an increase to interruptible rates in the next rate case be predetermined at this time. Rather, any change to interruptible base rates should be considered in the context the next rate case.

**Q. DOES THIS CONCLUDE YOUR CROSS-REBUTTAL TESTIMONY?**

A. Yes, it does.