

**BEFORE THE CORPORATION COMMISSION OF OKLAHOMA**

**APPLICATION OF PUBLIC SERVICE )  
COMPANY OF OKLAHOMA, AN )  
OKLAHOMA CORPORATION, FOR AN ) CAUSE NO. PUD 201300217  
ADJUSTMENT IN ITS RATES, AND )  
CHARGES FOR ELECTRIC SERVICE )  
IN THE STATE OF OKLAHOMA )**

**RESPONSIVE TESTIMONY  
OF  
MARK E. GARRETT**

**RATE DESIGN / COST OF SERVICE ISSUES**

**ON BEHALF  
OF  
OKLAHOMA INDUSTRIAL ENERGY CONSUMERS  
("OIEC")**

**MAY 7, 2014**

**Prepared Responsive Testimony of Mark E. Garrett**  
**May 7, 2013**  
**Cost of Service and Rate Design Issues**

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**I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY**

1 **Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A: My name is Mark Garrett.

3

4 **Q: WHAT IS YOUR PRESENT OCCUPATION?**

5 A: I am the President of Garrett Group, LLC, a firm specializing in public utility regulation,  
6 litigation and consulting services.

7

8 **Q: DID YOU FILE DIRECT TESTIMONY ON REVENUE REQUIREMENT**  
9 **ISSUES IN THIS CAUSE ON APRIL 21, 2014?**

10 A: Yes, I did. A description of my qualifications and a list of the proceedings in which I  
11 have been involved were included with that testimony.

12

13 **Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?**

14 A: I am appearing on behalf of Oklahoma Industrial Energy Consumers (OIEC).

15

16 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

17 A: The purpose of this testimony is to address PSO's cost of service study and proposed rate  
18 design. I also address PSO's Southwest Power Pool Transmission Cost ("SPPTC") rider  
19 and several other riders as well, such as PSO's fuel cost adjustment rider. I also address

1 recent changes in the AEP West Operating Agreement and I address the sharing ratio of  
2 PSO's off-system sales margins.

**II. PSO CLASS COST OF SERVICE ALLOCATIONS**

3 **Q: PLEASE SUMMARIZE THE INFORMATION YOU REVIEWED IN**  
4 **PREPARING YOUR TESTIMONY WITH REGARD TO PSO'S COST OF**  
5 **SERVICE STUDY AND PROPOSED RATE DESIGN.**

6 A: I reviewed the direct prefilled testimonies of John Aaron and Jennifer Jackson, PSO's  
7 proposed tariffs, PSO's filed cost of service studies and proposed rate design, and PSO's  
8 responses to various data requests related to cost of service and rate design issues.

9  
10 **Q: DOES PSO'S FILED COST OF SERVICE STUDY PROVIDE A REASONABLE**  
11 **BASIS FOR ALLOCATION OF COSTS TO PSO'S CUSTOMER CLASSES?**

12 A: No. There are several problems with PSO's class cost of service study: (1) PSO  
13 proposes to change its transmission cost allocation methodology from a 4 Coincident  
14 Peak ("4 CP") methodology to a 12 Coincident Peak ("12 CP") methodology; (2) PSO  
15 understates revenues from the terminated Real Time Pricing ("RTP") program; and (3)  
16 PSO misallocates costs and revenues to the industrial classes using unreliable load data  
17 for the Large Power and Light Service Level 1 ("LPL1") and the Large Power and Light  
18 Service Level 2 (LPL2") classes. I discuss each of these problems in more detail below.

1 **II. A. TRANSMISSION ALLOCATION CHANGE FROM 4CP TO 12CP METHOD**

2 **Q: WHAT IS THE ISSUE REGARDING THE TRANSMISSION COST**  
3 **ALLOCATION CHANGE?**

4 A: PSO proposes to change its long-standing transmission cost allocation methodology  
5 from a 4 CP to a 12 CP methodology,<sup>1</sup> despite the fact that PSO has used the 4CP  
6 methodology in Oklahoma since 1996<sup>2</sup> and PSO's sister utility, AEP/SWEPCO, uses the  
7 4CP methodology for allocating transmission costs in both  
8 Arkansas and Texas.<sup>3</sup>

9  
10 **Q: WHAT REASON DID PSO GIVE FOR MAKING THIS CHANGE IN**  
11 **TRANSMISSION SYSTEM COST ALLOCATION?**

12 A: PSO states that the change was made to "synchronize the allocation of PSO's  
13 transmission-related costs with the method by which it is charged for services by the  
14 SPP."<sup>4</sup>

15  
16 **Q: IS A DESIRE TO SYNCHRONIZE PSO'S RETAIL CUSTOMER COST**  
17 **ALLOCATIONS WITH SPP'S ALLOCATIONS TO PSO SUFFICIENT**  
18 **REASON TO CHANGE PSO'S LONG-STANDING TRANSMISSION COST**  
19 **ALLOCATION METHODOLOGY?**

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1 John Aaron Testimony, page 15, lines 11 through 13.

2 See response to OIEC 21-9.

3 See response to OIEC 21-8.

4 John Aaron Testimony, page 15, lines 19 and 20.

1 A: No. A change of such an important and long-used allocation methodology should  
2 involve more than the consideration of one factor, such as how SPP allocates costs to  
3 PSO, especially when that factor has nothing to do with how PSO allocates costs to its  
4 retail customer classes. For retail transmission costs, it is much more important to  
5 synchronize the transmission cost allocations with how retail customers actually use the  
6 transmission system. The utility might want to also synchronize the transmission price  
7 signals with the production cost price signals the utility sends its customers. These  
8 synchronizations are actually meaningful from a cost allocation perspective. SPP's  
9 transmission charges to PSO are not a relevant factor for choosing a retail cost allocation  
10 methodology.

11  
12 **Q: HOW DO RETAIL CUSTOMERS USE THE PSO TRANSMISSION SYSTEM?**

13 A: PSO is clearly a summer peaking system for retail load. That is why both PSO's  
14 production costs and PSO's transmission costs have historically been allocated using a  
15 4CP allocation methodology.

16  
17 **Q: WHAT ABOUT THE OTHER FACTORS THAT SHOULD BE CONSIDERED**  
18 **(BUT WERE NOT CONSIDERED) BY PSO BEFORE CHANGING TO A 12CP**  
19 **METHODOLOGY?**

20 A: As for the price signals PSO's tariffs have been sending, and apparently will continue to  
21 send, PSO's industrial tariffs include a demand charge ratchet based on the customers'  
22 four peak months use, not based on 12 peak months use. Moreover, the change to a 12

1 monthly peak allocation penalizes industrial customers for responding to the tariff  
2 signals PSO has been sending. With a four-month peak season determined ratchet, PSO  
3 was sending a signal to reduce or manage industrial use during the peak season and  
4 period. To the extent that industrial customers responded to these signals and shifted or  
5 managed load to reduce their peak demand during those periods from what they might  
6 have otherwise been and shifted loads to other periods, the 12 CP allocation penalizes  
7 industrial customers for such responses. PSO's proposed industrial tariffs continue to  
8 have a four-month peak period ratchet design. In other words, PSO claims to be  
9 concerned with synchronizing its retail transmission cost allocations with its SPP charges,  
10 which serves no valid pricing purpose, but PSO is not concerned with synchronizing its  
11 retail transmission cost allocations with its overall rate structure, which serves a very  
12 compelling pricing purpose. If the industrial customers' rates are going to continue to be  
13 based in large part on a customer's four peak months' use, it is reasonable to continue to  
14 allocate transmission costs on the 4CP allocation method.

15  
16 **Q: WITH RESPECT TO PSO'S SISTER COMPANY IN TEXAS, AEP/SWEPCO,**  
17 **DID THE TEXAS COMMISSION FIND IT IMPORTANT TO SYNCHRONIZE**  
18 **SWEPCO'S RETAIL TRANSMISSION ALLOCATIONS WITH SPP**  
19 **ALLOCATIONS?**

20 **A:** Apparently not. In SWEPCO's most recent rate case in Texas, Docket No. 40443,  
21 SWEPCO requested to change to a 12CP allocation for transmission costs, but the Texas  
22 Commission instructed SWEPCO to retain a 4CP methodology.

1 "The Commission's history of adoption of the A&E/4CP method and the  
2 Commission's unqualified support gives the method even greater  
3 persuasive authority. The ALJs recommend the Commission's adoption  
4 of the A&E/4CP method, as proposed by TIEC and Staff, because that  
5 method accounts for the most reasonable method of allocation of  
6 transmission costs.'

7 **Q: WHAT ALLOCATION METHODOLOGY DOES OG&E USE FOR**  
8 **TRANSMISSION COST ALLOCATION IN OKLAHOMA?**

9 A: OG&E uses a 4CP allocation for allocating transmission costs in Oklahoma. OG&E  
10 uses a 4CP methodology because it best reflects how retail customers use the  
11 transmission system.

12  
13 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO THE COMPANY'S**  
14 **REQUEST TO CHANGE ITS TRANSMISSION COST ALLOCATION TO A**  
15 **12CP METHOD?**

16 A: I recommend that the Commission reject PSO's requested change and continue to use the  
17 4CP methodology.

18  
19 **II. B. REAL TIME PRICING ("RTP") REVENUE ATTRIBUTION ERRORS**

20 **Q: WHAT IS THE ISSUE REGARDING RTP REVENUES?**

21 A: PSO recently ended the RTP program in Cause No. PUD 201300201. In the current  
22 cause, PSO miscalculates revenues attributable to customers using the RTP program by  
23 including only revenues up to the customer base line ("CBL") in the cost of service  
24 study. PSO fails to include RTP revenues purchased above the CBL during the test year.

1 This omission understates both LPL sales and revenues. My adjustment adds back the  
2 kWh purchased above the CBL and the associated revenues. The revenue adjustment is  
3 calculated by multiplying the kWh above the CBL by the non-fuel kWh charge related to  
4 each specific rate code.  
5

6 **Q: WHY IS THIS ADJUSTMENT NECESSARY?**

7 A: During the test year, RTP customers purchased more kWh than the CBL kWh estimate.  
8 It would be expected that customers would continue to purchase the same level of kWh  
9 in support of their work processes. While customers may have been able to take  
10 advantage of the RTP program to save money during the existence of the program, the  
11 mere ending of the program does not mean these customers will suddenly reduce  
12 consumption. The necessary revenue adjustments to reflect actual kWh purchased by  
13 RTP customers in the test year under the RTP program are as follows;

14	Rate	kWh Adjustment	NF Revenue
15	LPL1	19,597,360	\$ 34,609
16	LPL2	78,017,564	\$165,397
17	LPL3	34,422,421	\$104,059
18	<u>LPL5</u>	<u>2,099,298</u>	<u>\$ 16,249</u>
19	TOTAL	134,136,643	\$320,314
20			

21 **Q: ARE THERE ANY ADDITIONAL RTP RELATED ADJUSTMENTS?**

---

1 A: Yes. An additional adjustment to increase LPL1 class non-fuel revenue by \$97,881 was  
2 supported in PSO's Rebuttal Exhibit SGJ-2R filed in Cause No. PUD 201300201, the  
3 cause that ended RTP. This adjustment reflects the additional charges that the LPL1  
4 customers will pay in standby charges as the RTP program ends. This adjustment  
5 increases LPL1 non-fuel revenue by \$97,881.

6

7 **II. C. INDUSTRIAL CLASS REVENUE ATTRIBUTION ERRORS**

8 **Q: DID YOU FIND OTHER ERRORS IN PSO'S ADJUSTMENTS TO THE**  
9 **INDUSTRIAL CLASS?**

10 A: Yes. In this case, PSO increased the LPL2 kW demand levels used to assign customer  
11 class responsibility by 4% from the previous rate case, with no explanation. The kW  
12 demand units assigned to the LPL2 class in the last rate case totaled 3,822,638. In this  
13 case, the equivalent number has risen to 3,974,704, which is a 4% increase over the last  
14 case.

15 A 4% increase is higher than expected since the loads of the LPL2 class have  
16 been relatively stable over the past several years. A further concern is that revenues in  
17 the LPL2 class have decreased since the last rate case, according to PSO. In the last rate  
18 case, PSO assigned \$30,104,629 non-fuel base revenues to the LPL2 class, but in this  
19 case, PSO assigned revenues of only \$28,994,864 to the class. That is a 4% decrease in  
20 revenues. With a 4% increase in demand levels one would expect a corresponding  
21 increase in revenue levels, not a decrease. In other words, PSO's increase in cost  
22 assignment to the LPL2 class through higher class demand levels without a

1 corresponding increase in revenue levels makes no sense. If demand has indeed  
2 increased then non-fuel revenue would be expected to increase as well.  
3

4 **Q: HOW DO WE KNOW THAT REVENUE LEVELS WOULD HAVE TO**  
5 **INCREASE WITH HIGHER DEMAND LEVELS?**

6 A: PSO's tariffs for LPL customers have an aggressive demand ratchet for on peak billing  
7 demand. What the demand ratchet requires is that customers pay at least 90 percent of  
8 the peak billing demand for the next eleven months regardless of the recorded demand in  
9 following months. So one would expect demand revenues in the LPL2 class to be  
10 significantly higher in the test year if properly adjusted for this effect. In fact, I calculate  
11 that if the demand-ratchet on a 4% demand increase is taken into account, it would  
12 increase non-fuel base revenues by \$718,848. This amount estimates the expected  
13 minimum revenue that should occur if demand for this class has indeed increased 4% for  
14 this class.  
15

16 **Q: IS THERE ANOTHER WAY TO CORRECT PSO'S ALLOCATIONS TO THE**  
17 **LPL2 CLASS?**

18 A: Yes. Another approach would be to adjust class demands to match class revenues. This  
19 second approach would adjust kW demand used to allocate production and transmission  
20 costs to the LPL2 class to a more appropriate (or normal) level. To develop the  
21 necessary reduction, I started with the 1.1% increase to peak billing demand supported  
22 by PSO. I then look at the allocation demand units supported by PSO in the most

1 previous rate case (2010). In that case the billing demand fairly matched the allocation  
2 demand units. My adjustment in this case increases the allocation demand units  
3 supported by PSO in the 2010 rate case by the 1.1 percent billing demand supported by  
4 PSO in the current case. This adjustment would result in a much lower cost assignment  
5 to the LPL2 class than the assignment supported by PSO. The adjustment would reduce  
6 the LPL2 four summer peak average demands (4CP) from 357,221 kW to 346,367 kW.  
7 The adjusted number is then used to calculate Transmission and Production costs  
8 assignments to the LPL2 class.  
9

10 **Q: IN YOUR CLASS COST OF SERVICE STUDY DID YOU INCREASE**  
11 **REVENUES OR DECREASE DEMAND?**

12 A: Either approach gets to the same result. In my cost of service study, I reduced demand  
13 levels to the Company's supported 1.1% increase. With the exception of the added RTP  
14 related revenues that I previously discussed, I accepted PSO's filed revenues for the  
15 LPL2 class. The calculations are available in my work papers.  
16

17 **Q: WHAT ADJUSTMENT DID YOU FIND NECESSARY CONCERNING THIS**  
18 **MATTER FOR THE LPL1 CLASS?**

19 A: The same concerns raised regarding the LPL2 class are also present for the LPL1 class.  
20 In the current case, PSO increased the LPL1 kW demand responsibility for the LPL1  
21 class by more than 10 percent over the last rate case. The kW demand assigned to the  
22 LPL1 class in the most previous rate case (2010) was 805,851. In the current case, the

1 equivalent number is 889,958. The increase to the four summer months, the months  
2 used to develop the production and transmission allocations, is an astonishing 18%  
3 increase. Again, however, there is no corresponding increase in revenues attributed to  
4 the LPL1 class. PSO only increased billing demand about 5 percent. As with the LPL2  
5 class, the demand used to bill LPL1 customers does not match the demand used to  
6 allocate production and transmission costs to the class. One would expect demand  
7 revenues to be up greatly for the test year if properly adjusted for the demand ratchet  
8 effect. If revenue from the demand ratchet effect is taken into account, it would be  
9 necessary to increase non-fuel revenues for the LPL1 class by a minimum by \$595,253.  
10 This amount estimates the expected minimum revenue that should occur if demand for  
11 this class has indeed increased to the level claimed by PSO for this class. This  
12 adjustment coupled with the RTP adjustment of \$132,490 would result in a total  
13 increased non-fuel revenue adjustment of \$727,743 for the LPL1 class. The details of  
14 this adjustment can be found in my work papers.

15  
16 **Q: AS WITH THE LPL2 CLASS, DID YOU DECIDE TO REDUCE THE LPL1**  
17 **DEMAND USED FOR PRODUCTION AND TRANSMISSION COST**  
18 **ALLOCATIONS AND KEEP THE CLASS REVENUES SUPPORTED BY PSO?**

19 A: Yes. I reduced the LPL1 class peak responsibility for purposes of production and  
20 transmission cost allocations and used the PSO filed class revenues. My adjustment  
21 increases the allocation demand units used in the 2010 rate case by the 5.5 percent  
22 billing demand increase supported by PSO in the current case. This adjustment results in

1 lower cost assignments to the LPL1 class. The LPL1 four summer peak average  
2 demands (4CP) of 82,204 kW as supported by PSO are adjusted to 73,318. The latter  
3 number is used to calculate the Transmission and Production costs assignments to the  
4 LPL1 class. The calculations are available in my work papers.

5  
6 **Q: DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE INDUSTRIAL**  
7 **CLASSES?**

8 A: Yes. PSO has recommended very large increases to customer charges for the industrial  
9 classes. In my opinion, the current customer charges are sufficient, and should remain at  
10 their current levels. Therefore, the method to implement any change needed to meet the  
11 class assigned revenue requirement is to change the rate components to the industrial  
12 classes using an equal across-the-board change to demand and energy charges applied as  
13 needed to achieve the revenue requirement assigned to each specific class.

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### **III. RATE DESIGN AND ALLOCATION OF RATE CHANGE**

14 **Q: IS PSO'S PROPOSED RATE ALLOCATION TO THE CLASSES ACCEPTABLE**  
15 **FROM A RATEMAKING PERSPECTIVE?**

16 A: No. PSO's proposed rate design would significantly increase the non-fuel rates for the  
17 large industrial customers in LPL2 and LPL1 classes. PSO's rate design would increase  
18 the LPL2 non-fuel rates 20.45% and LPL1 non-fuel rates by 18.81%. These increases  
19 are significantly larger than PSO's proposed increase of 6.95% to the other classes.

1 **Q: IS PSO'S PROPOSED RATE ALLOCATION TO THE INDUSTRIAL CLASSES**  
2 **ACCEPTABLE FROM A POLICY PERSPECTIVE?**

3 A: No. PSO's proposed increase for LPL1 and LPL2 customers could severely impact the  
4 manufacturing industry in Oklahoma if implemented. Moreover, the proposed increases  
5 are based on a severely flawed cost of service study that should never have been filed.  
6 The mismatches in the study between class demands used for cost assignments and class  
7 demands used for revenue assignments should have been indicated by the  
8 disproportionate increases in the industrial classes compared to other classes, sufficient  
9 to catch these mistakes before the case was filed.

10  
11 **Q: DID OIEC AND OTHER PARTIES RECOMMEND LOWER REVENUE**  
12 **REQUIREMENTS THAN THE REVENUE REQUIREMENT REQUESTED BY**  
13 **PSO?**

14 A: Yes. PUD Staff, the Attorney General, and OIEC all filed testimony recommending  
15 lower revenue requirements than the revenue requirement requested by PSO.

16  
17 **Q: WHAT WOULD BE THE CLASS DOLLAR VALUES IF ALL CLASSES WERE**  
18 **MOVED TO COST OF SERVICE USING OIEC'S REVENUE REQUIREMENT**  
19 **DECREASE AND OIEC'S CORRECTED COST OF SERVICE STUDY?**

20 A: The required rate increases and reductions by class are summarized in Table 1 below.

**Table 1: OIEC Full Cost of Service Base Rate Change**

<b>Customer Class</b>	<b>OIEC Proposed Rate Increase</b>	<b>OIEC ROR</b>
Residential	\$3,959,114	7.33%
Lighting	\$1,193,797	7.33%
Commercial	(\$22,209,345)	7.33%
SL-3	\$(4,178,295)	7.33%
SL-2	(\$247,667)	7.33%
SL-1	(\$682,964)	7.33%
<b>Total Rate Increase/Decrease ROR – All Classes</b>	<b>(\$22,165,360)</b>	<b>7.33%</b>

1 **Q: DO YOU RECOMMEND TAKING ALL OF THE CLASSES TO COST OF**  
 2 **SERVICE BASED ON YOUR CORRECTED COST OF SERVICE STUDY?**

3 A: No. In this case, the Company's filed cost of service study is sufficiently flawed as to  
 4 render it unreliable as a basis for cost allocation to the classes. Although I found and  
 5 corrected material errors in the industrial classes, I cannot say that the entire study, even  
 6 with these corrections, is now sufficiently reliable. The corrected study also provides  
 7 rate increases to some classes and rate decreases to others, which I am reluctant to  
 8 recommend after only correcting the errors in the LPL classes. Therefore, I recommend  
 9 that whatever rate increase or decrease is ultimately ordered in this case it be spread to  
 10 the classes on an equal percentage basis, meaning a 3.69% overall decrease, for example,  
 11 would result in a 3.69% decrease to each class. The same would be true for an increase,  
 12 if one is ordered. It would be spread to the customer classes on an equal percentage  
 13 basis.

#### **IV. RIDER ISSUES**

##### **IV. A. SPP TRANSMISSION COST RECOVERY RIDER**

1 **Q: PLEASE DESCRIBE PSO'S EXISTING SPPTC TARIFF.**

2 A: PSO's SPPTC tariff was first authorized in October of 2011 pursuant to the Joint  
3 Stipulation and Settlement Agreement and findings adopted by the Commission in Order  
4 No. 591185 in Cause No. PUD 201100106. The purpose of the SPPTC tariff was to  
5 allow PSO to recover its Oklahoma retail jurisdiction share of certain third party SPP  
6 Base Plan Fees charged to the Company that are over and above amounts collected  
7 through PSO's base rates. The SPPTC tariff provides for PSO to collect projected SPP  
8 Base Plan charges, with provisions for annual filings in September of each year at which  
9 time adjustments are made to true-up the prior year charges to actual expenses and, if  
10 needed, to revise the SPPTC tariff charge to reflect projected expense increases for the  
11 next year. (See Exhibit MG-1, PSO's existing SPPTC Tariff.)

12  
13 **Q: WHAT IS THE NATURE OF THE THIRD PARTY SPP BASE PLAN FEES  
14 THAT ARE RECOVERABLE THROUGH THE SPPTC TARIFF?**

15 A: The SPPTC tariff allows PSO to recover charges for transmission service billed to the  
16 Company under Schedule 11 of SPP's Open Access Transmission Tariff ("OATT").  
17 Schedule 11 charges represent costs for transmission services provided by SPP  
18 transmission owners' facilities that are designated by SPP as Base Plan Upgrades.  
19 (Sartin Direct, page 14.) Specifically, the SPPTC tariff allows PSO to recover Schedule

1 11 charges for transmission projects constructed by third party transmission owners,  
2 excluding costs of projects constructed by AEP affiliates other than Southwestern  
3 Electric Power Company (“SWEPCO”) or Southwest Transmission Company (“SW  
4 Transco”). (See Exhibit MG-1.)  
5

6 **Q: WHAT RELIEF IS PSO REQUESTING IN THIS CASE WITH REGARD TO ITS**  
7 **SPPTC TARIFF?**

8 A: PSO has made two primary requests regarding its SPPTC tariff in this case. First, the  
9 Company requests that the Commission find that amounts recovered to date through the  
10 SPPTC tariff “were reasonable, eligible for recovery, properly calculated, and  
11 appropriately allocated to PSO’s various customer rate classes.” (See PSO witness  
12 Sartin’s Direct Testimony, page 13.) In addition, PSO is requesting approval to  
13 significantly expand the charges collected through its SPPTC tariff to include SPP  
14 Schedule 9 charges for Network Integration Transmission Service (“NITS”) and to also  
15 include Schedule 11 and Schedule 9 charges associated with transmission projects  
16 owned by all other AEP affiliates, including OK Transco. (Sartin Direct, page 15.)  
17

18 **Q: WHAT ARE SCHEDULE 9 CHARGES?**

19 A: SPP Schedule 9 charges represent amounts paid for transmission services provided over  
20 lines located within the AEP West Zone of SPP. (Sartin Direct, page 15.) Unlike  
21 Schedule 11 charges, which recover the costs of primarily high voltage transmission  
22 lines that are allocated to all transmission customers within the SPP region, Schedule 9

1 charges generally represent the local transmission grid that primarily supplies (and  
2 whose costs are allocated to) PSO and other transmission customers located within the  
3 AEP West Zone. In the past, PSO and its affiliate Southwestern Electric Power  
4 Company (“SWEPCO”) owned and constructed the majority of lines that now are  
5 included within the Schedule 9 charges; however, over the last several years AEP has  
6 decided that affiliated transmission companies, including OK Transco and Southwest  
7 Transco (“SW Transco”) should own and construct most new transmission facilities  
8 within the PSO and SWEPCO service areas.

9  
10 **Q: ARE THERE ANY OTHER ISSUES WHICH NEED TO BE ADDRESSED IN**  
11 **THIS CASE REGARDING THE SPPTC TARIFF?**

12 A: Yes. The Commission specified in Paragraph 7 of Order No. 591185 that no later than  
13 twenty-six months following the date of the Order (i.e., by February 18, 2014), PSO  
14 should file a general base rate case for the purpose of determining whether the SPPTC  
15 Tariff should be amended, extended or terminated and for the purpose of reviewing  
16 PSO’s testimony supporting past annual SPPTC Tariff true-up and redetermination  
17 filings. Therefore, a key issue to be decided in this case is whether the SPPTC Tariff  
18 should be continued or terminated.

19  
20 **Q: WHAT REQUIREMENTS WERE ESTABLISHED BY THE COMMISSION FOR**  
21 **APPROVAL OF AMOUNTS COLLECTED UNDER PSO’S SPPTC TARIFF?**

1 A: In approving the SPPTC tariff in Order No. 591185 in Cause No. PUD 201100106, the  
2 Commission established a number of requirements which must be met by PSO to  
3 demonstrate the reasonableness of amounts collected through its SPPTC tariff. For  
4 example, under Paragraph 5 of the Order, the Company is required to provide testimony  
5 supporting the proposed SPPTC tariff as well as information regarding the costs and  
6 benefits of specific transmission projects underlying SPPTC charges as well as the rate  
7 impact of proposed SPPTC charges on each customer class.

8 In addition, under Paragraph 6 of Order No. 591185, PSO was required to submit  
9 testimony in its next general base rate case (i.e., in this case) which addresses the  
10 reasonableness of amounts collected through the SPPTC tariff, including:

- 11 1) Identifying each of the third-party upgrades recovered from Oklahoma retail  
12 customers and identifying the benefits (economic or otherwise) that such  
13 upgrades and facilities provide to the regional grid and PSO's Oklahoma  
14 retail customers;
- 15 2) Demonstrating that the amounts recovered under its SPPTC Tariff were  
16 reasonable, eligible for recovery, properly calculated, and appropriately  
17 allocated to PSO's various customer rate classes;
- 18 3) Demonstrating that the facilities were approved by the SPP, and the costs of  
19 such upgrades are included in FERC approved rates and allocated to PSO  
20 under a FERC approved SPP cost allocation methodology; and  
21 4) Identifying the rate impact on PSO's various customer classes of the amounts  
22 recovered by PSO pursuant to the SPPTC Tariff and also identifying the rate  
23 impact of the amounts projected to be recovered by PSO pursuant to its  
24 SPPTC Tariff.  
25  
26  
27  
28

1 **Q: HAS PSO PROVIDED ALL INFORMATION SPECIFIED BY THE**  
2 **COMMISSION'S FINAL ORDER IN CAUSE NO. PUD 201100106 TO SUPPORT**  
3 **AMOUNTS COLLECTED THROUGH ITS SPPTC TARIFF?**

4 A: No. PSO has presented testimony of several witnesses in this case which generally  
5 address the reasonableness of past amounts collected through the existing SPPTC Tariff.  
6 In addition, PSO has provided the testimony and supporting workpapers provided to  
7 support annual SPPTC Tariff redetermination filings made in September of 2012 and  
8 September of 2013. However, the Company has not addressed the economic benefits of  
9 such projects to Oklahoma, nor has it demonstrated that such amounts were reasonable  
10 or included in FERC approved rates, as required by Paragraph 6 of Order No. 591185 in  
11 Cause No. PUD 201100106.

12 For example, PSO admits that it has no analysis of the benefits of specific  
13 transmission projects whose costs are recovered through the SPPTC Tariff. (See Exhibit  
14 MG-2, PSO's response to OIEC 13-5.) PSO further admits that the cost/benefit studies  
15 that were performed by SPP for a group of transmission projects, including certain  
16 projects recovered through the Company's SPPTC Tariff, only address benefits on a  
17 region wide basis and therefore do not identify the benefits to Oklahoma. (See Exhibit  
18 MG-3, PSO's response to OIEC 13-6.) Moreover, there have been significant cost over-  
19 runs in the original budgets of many of the associated transmission projects. In short,  
20 PSO has not demonstrated that the transmission projects whose costs are recovered  
21 through its SPPTC Tariff have any benefit to Oklahoma retail customers.  
22

1 **Q: HAS PSO DEMONSTRATED THAT THE COSTS RECOVERED THROUGH**  
2 **ITS SPPTC TARIFF WERE REASONABLE?**

3 A: No. Serious questions also exist regarding the reasonableness of the costs of the  
4 transmission projects which PSO has recovered and seeks to continue to recovery  
5 through its SPPTC Tariff. For example, according to the SPP's most recent transmission  
6 project tracking report, approximately 122 transmission projects, including projects  
7 whose costs have been recovered through the Company's SPPTC Tariff, have  
8 experienced cost over-runs of at least 20% over the original SPP-authorized project  
9 budgets; the total budget over-run for all 569 projects currently monitored by SPP is  
10 more than \$1.2 billion (22.9%). (See Exhibit MG-4.) However, despite these significant  
11 cost over-runs PSO admits that it has not intervened in any case to question the  
12 reasonableness of these third-party owned transmission projects. (See Exhibit MG-5,  
13 PSO's responses to OIEC data requests 11-6 through 11-12). Moreover, there are no  
14 witnesses from SPP or third party transmission owners in this case testifying regarding  
15 the reasons for project cost over-runs or to otherwise support the amounts PSO has  
16 recovered through its SPPTC.

17  
18 **Q: WERE THE COSTS WHICH PSO SEEKS TO RECOVER THROUGH ITS**  
19 **SPPTC TARIFF APPROVED BY THE FERC?**

20 A: No. The costs of third-party owned transmission projects whose costs are recovered  
21 through PSO's SPPTC Tariff are recovered through formula transmission rates. The  
22 transmission rate formulas were filed with the FERC, and in virtually all instances

1 accepted for filing without hearing, and without an order of the FERC explicitly  
2 approving the rate formulas. However, the actual costs recovered through such rates  
3 have not been reviewed or approved by the FERC. Furthermore, PSO indicates that it  
4 has not intervened to challenge formula rates filed with FERC by any third party  
5 transmission owner within SPP; although as a transmission customer it had every right,  
6 and arguably an obligation, to do so. (See Exhibit MG-5, PSO's responses to OIEC data  
7 requests 11-6 through 11-12.)  
8

9 **Q: DOES THE ACCEPTANCE FOR FILING OF TRANSMISSION RATE**  
10 **FORMULAS CONSTITUTE APPROVAL BY THE FERC OF THE COSTS OF**  
11 **THIRD PARTY OWNED TRANSMISSION PROJECTS WHICH HAVE BEEN**  
12 **RECOVERED THROUGH PSO'S SPPTC TARIFF?**

13 **A:** No. In most cases the acceptance of the transmission rate formulas of third party  
14 transmission owners occurred years earlier than the costs at issue in this case were even  
15 incurred; therefore the FERC could not have approved such costs. Moreover, in virtually  
16 every case, the FERC made it clear that in accepting the filing of transmission rate  
17 formulas, it was not approving any specific charge or ratemaking principle. For  
18 example, in an August 2011 letter Order accepting formula rate revisions proposed by  
19 Kansas City Power & Light Company ("KCP&L") which are the basis for Schedule 11  
20 charges that could be recovered through PSO's SPPTC Tariff, the FERC's Director,  
21 Division of Electric Power Regulation, qualified the approval of KCP&L's proposed  
22 formula rate as follows:

1 This action does not constitute approval of any service, rate, charge,  
2 classification, or any rule, regulation, contract, or practice affecting such rate or  
3 service provided for in the filed documents . . .

4  
5 (See Exhibit MG-7.) Similar qualifications were included in the orders accepting for  
6 filing the formula rates of other SPP transmission owners. (See Exhibit MG-7.) These  
7 explicit qualifiers refute PSO's claims that FERC has approved the formula rates and the  
8 third party owned transmission project costs which have been recovered through PSO's  
9 SPPTC Tariff. (See Sartin Direct, pages 13-14 and Exhibit MG-7.)

10 **Q: DID PSO HAVE THE OPPORTUNITY TO SEEK THE FERC'S REVIEW AND**  
11 **APPROVAL OF CHARGES FOR THIRD PARTY TRANSMISSION PROJECTS**  
12 **WHICH HAVE BEEN RECOVERED THROUGH THE SPPTC TARIFF?**

13 A: Yes. The formula transmission rates of third party transmission owners are periodically  
14 updated to include costs of new transmission projects. PSO has the right to review such  
15 charges and to file a complaint with the FERC to address charges which may appear to  
16 be unreasonable. For example, PSO certainly could have questioned the significant cost  
17 over-runs experienced for third-party transmission projects, as well as the relatively high  
18 return on equity ("ROE") requested for such projects. In fact there are numerous  
19 potential ratemaking and accounting issues reflected in third party formula rate updates  
20 which are based, at least in part, on projected costs. These types of issues are routinely  
21 challenged by OIEC and other interveners in PSO retail rate cases, and such challenges  
22 almost always lead to regulatory adjustments and lower cost recovery levels than  
23 originally requested by the Company. Notwithstanding this fact, and the fact that

1 Paragraph 6 of Order No. 591185 required PSO to demonstrate that third party charges  
2 recovered through its SPPTC Tariff are reasonable and included in FERC-approved  
3 rates, PSO admits that since 2010 it has not contested the formula rate updates or  
4 proposed ratemaking adjustments of any SPP transmission owner in any proceeding  
5 before the FERC. (See Exhibit MG-5, PSO's responses to OIEC 11-6 through 11-12).  
6 PSO's failure to challenge transmission charges from third party transmission owners in  
7 SPP, and the lack of regulatory review of such charges, raise serious questions regarding  
8 the reasonableness of amounts collected through the Company's SPPTC Tariff.  
9

10 **Q: ARE THERE OTHER FACTORS THAT MAKE IT DIFFICULT TO VERIFY**  
11 **THE REASONABLENESS OF AMOUNTS COLLECTED BY PSO THROUGH**  
12 **ITS SPPTC TARIFF?**

13 **A:** Yes. The SPPTC Tariff charges are based on PSO's projections of third party charges  
14 for Schedule 11 service over an annual review period. Moreover, the costs included in  
15 third party formula rates that PSO seeks to recover through its SPPTC Tariff are also  
16 projected costs; however, there is no evidence in this case to establish that these cost  
17 projections reflected in Schedule 11 charges to PSO from each party are reasonable.  
18 Moreover, unlike PSO's Fuel Cost Adjustment ("FCA") Rider, which adjusts for the  
19 difference between forecasted costs used in setting the FCA Rider and the actual  
20 incurred fuel costs that are supported by fuel supplier invoices, the annual true-up for  
21 amounts collected through PSO's SPPTC Tariff is based on the difference between  
22 PSO's forecast of Schedule 11 charges and third party transmission owners' cost

1 projections that serve as the basis for amounts collected through SPP Schedule 11  
2 charges. This true up for differences between PSO's forecasts and third party  
3 transmission cost projections of Schedule 11 transmission charges introduces significant  
4 uncertainty in SPPTC Tariff charges, and makes it virtually impossible to verify the  
5 reasonableness of these forecasted charges.

6  
7 **Q: PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE**  
8 **REASONABLENESS OF THIRD PARTY CHARGES RECOVERED THROUGH**  
9 **PSO'S SPPTC TARIFF.**

10 **A:** PSO has not demonstrated that the third party transmission charges recovered through  
11 the SPPTC Tariff during the 2012 and 2013 review periods are reasonable, and such  
12 charges have not been approved by the FERC as required under Paragraph 6 of the  
13 Commission's Order adopting the SPPTC in Cause No. PUD 201100106. According to  
14 reports by SPP, there have been significant cost over-runs in the cost of transmission  
15 projects that have been recovered through the SPPTC and PSO has not questioned such  
16 costs in formula rate update proceedings or by filing complaints with the FERC. (See  
17 Exhibit MG-5.) Furthermore, there is no evidence as to how or if such projects benefit  
18 Oklahoma retail customers. Given the fact that PSO failed to provide the information  
19 specified in Paragraph 6 of the SPPTC Tariff, which is necessary to demonstrate the  
20 reasonableness of projected third party costs the Company has recovered through the  
21 tariff, it would not be unreasonable to disallow all amounts recovered to date through  
22 PSO's SPPTC Tariff. For this and other reasons discussed later in my testimony, I

1 recommend that the SPPTC Tariff be discontinued immediately. However, in the event  
2 the SPPTC Tariff is continued, I recommend that the portion of forecasted third party  
3 Schedule 11 charges recovered through the SPPTC Tariff associated with third party  
4 owned transmission projects be limited to an amount based on the SPP-approved original  
5 budget for each project. Under this recommendation, PSO would have the opportunity  
6 in a base rate case to demonstrate that it should be allowed to recover any additional  
7 amount of third party Schedule 11 charges associated with project cost increases over the  
8 original approved budgets; however, such amounts would not be recoverable through the  
9 SPPTC Tariff.

#### 10 **PROPOSED EXPANSION OF SPPTC TARIFF**

11 **Q: WHAT IS PSO'S PROPOSAL REGARDING FUTURE EXPANSION OF THE**  
12 **SPPTC TARIFF?**

13 **A:** PSO requests that the Commission authorize the Company to expand the SPPTC Tariff  
14 to: 1) recover SPP Schedule 9 Charges for Network Integration Transmission Service  
15 ("NITS") and 2) to recover SPP Schedule 11 and Schedule 9 charges from OK Transco  
16 and all other PSO affiliated transmission companies that provide such services. (Sartin  
17 Direct, page 14)

18  
19 **Q: WHAT IS THE ANTICIPATED IMPACT OF PSO'S PROPOSALS TO EXPAND**  
20 **THE SPPTC TARIFF TO INCLUDE SCHEDULE 9 CHARGES AS WELL AS**  
21 **CHARGES FROM ALL PSO TRANSMISSION AFFILIATES?**

1 A. PSO's proposals to expand amounts collected through its SPPTC Tariff will greatly  
2 increase the level of costs collected through this tariff. For example, over the last two  
3 years PSO collected approximately \$15 million per year through the SPPTC Tariff for  
4 Schedule 11 charges from third party transmission owners within SPP. These amounts  
5 collected through PSO's SPPTC Tariff equate to approximately 15% of PSO's total SPP  
6 charges during this period. However, under the Company's proposal to expand the  
7 SPPTC Tariff to include Schedule 9 charges plus charges from all PSO transmission  
8 affiliates, the level of charges collected through the SPPTC Tariff is forecasted to rise to  
9 more than \$130 million per year, which would represent just over 75% of PSO's total  
10 SPP charges, and more than 10% of PSO's total system revenue requirement.

11

12 **Q: WHAT JUSTIFICATION HAS PSO PROVIDED FOR ITS PROPOSAL TO**  
13 **EXPAND THE SPPTC TARIFF TO COLLECT SUCH AN**  
14 **EXTRAORDINARILY HIGH LEVEL OF SPP CHARGES OUTSIDE OF BASE**  
15 **RATES?**

16 A: PSO witness Sartin indicates that the Company's proposal to expand the SPPTC Tariff to  
17 include Schedule 9 charges is "because of dramatic cost increases expected for these  
18 transmission services over the next several years." (Sartin Direct, page 14) However, as  
19 shown below, the forecasted dramatic increase in third party Schedule 9 charges Mr.  
20 Sartin refers to represents only a small fraction of PSO's total system revenue  
21 requirement and is well within the normal range of year-to-year variation in expenses

1 and revenues (both increases and decreases) that is experienced between base rate cases  
2 due to changes in weather, customer growth, outages and other factors.

3

Forecasted Increase in 3rd Party Schedule 9 Charges

	<u>3rd Party Sch 9</u>	<u>Increase</u>	<u>Est. Total RevRqt</u>	<u>% of Total RevRqt</u>
2013	\$21,000,000			
2014	\$24,000,000	\$3,000,000	\$1,208,004,944	0.248%
2015	\$29,000,000	\$5,000,000	\$1,220,084,993	0.410%
2016	\$38,000,000	\$9,000,000	\$1,232,285,843	0.730%
2017	\$41,000,000	\$3,000,000	\$1,244,608,702	0.241%
2018	\$47,000,000	\$6,000,000	\$1,257,054,789	0.477%

Note: Source of 3rd Party Sch 9 Charges is Sartin Direct, page 14.

4

5 In light of the relatively modest forecasted increase in third party Schedule 9 charges,  
6 there is no justification for allowing the exceptionally generous ratemaking treatment  
7 that is afforded under the SPPTC Tariff as PSO proposes.

8

9 **Q: WHY DO YOU CONSIDER THE RATEMAKING TREATMENT OF**  
10 **TRANSMISSION CHARGES UNDER PSO'S SPPTC TARIFF TO BE**  
11 **EXCEPTIONALLY GENEROUS TO PSO?**

12 **A:** The projected costs of transmission investments which PSO recovers through the SPPTC  
13 Tariff are not subject to any regulatory review or approval process, except in rare  
14 instances. The Schedule 11 and Schedule 9 charges reflect cost projections prepared by  
15 third party transmission owners, which have not been contested by PSO, and whose

1           reasonableness cannot be verified. Moreover, these projected costs are based on  
2           relatively high return on equity (“ROE”) levels (e.g., in excess of 11%) and in some  
3           instances include construction work in progress for projects that are not even in service.  
4           For all of these reasons, the ratemaking treatment of third party transmission costs  
5           recovered under PSO’s SPPTC Tariff is exceptionally generous to the Company when  
6           compared to rate treatment which otherwise would apply under the OCC’s normal base  
7           ratemaking policies.

8  
9           **Q: ARE THERE OTHER REASONS WHY PSO’S PROPOSAL TO INCLUDE**  
10           **THIRD PARTY SCHEDULE 9 CHARGES IN ITS SPPTC TARIFF SHOULD**  
11           **NOT BE ADOPTED?**

12           A: Yes. The majority of third party Schedule 9 charges which PSO proposes to include in  
13           its SPPTC Tariff are due to transmission investments by OK Transco in PSO’s service  
14           area. In Cause No. PUD 201100106, PSO witness Robert Pennybaker explained that  
15           the Company was not seeking to recover OK Transco transmission investment costs  
16           through the SPPTC Tariff because such costs were incurred for facilities that PSO  
17           otherwise would have owned and collected through PSO’s base rates.

18  
19                           **Q: WILL SPP REGIONAL COSTS RELATED TO OKLAHOMA**  
20                           **TRANSMISSION COMPANY OWNED FACILITIES BE INCLUDED IN**  
21                           **THE PROPOSED TARIFF?**

22  
23                           A. No. PSO recognizes that OK Transco investment represents costs that  
24                           would have otherwise been included in PSO’s base rates. Accordingly, PSO will

1 address OK Transco costs in its base rate cases, and will expressly exclude them  
2 from collection through this tariff.

3  
4 (Direct Testimony of Robert L. Pennybaker, page 15, OCC Cause No. PUD  
5 201100106.)  
6

7 PSO has not offered any compelling reason why the above reasons stated by Mr.  
8 Pennybaker for excluding OK Transco costs from the SPPTC Tariff are not still  
9 applicable in this case.  
10

11 **Q: HAS PSO PROVIDED ANY REASONABLE JUSTIFICATION FOR ITS**  
12 **PROPOSAL TO EXPAND THE SPPTC TARIFF TO INCLUDE CHARGES**  
13 **FROM OK TRANSCO AND OTHER PSO TRANSMISSION AFFILIATES?**

14 A: No. The OCC has traditionally required a heightened level of scrutiny of affiliate  
15 transactions. However, under PSO's proposal to expand the SPPTC Tariff to recover  
16 Schedule 11 and Schedule 9 charges from all PSO transmission affiliates, there would be  
17 virtually no regulatory oversight and arguably little or no OCC control over the level of  
18 such unregulated affiliate charges. The Commission should not allow PSO to use the  
19 SPPTC Tariff to circumvent the OCC's jurisdiction over transmission charges from  
20 PSO's affiliates.  
21

22 **Q: WHAT IS YOUR RECOMMENDATION REGARDING THE FUTURE**  
23 **DISPOSITION OF THE SPPTC TARIFF?**

24 A: Due to a variety of reasons, it has been extremely difficult to verify the reasonableness of  
25 costs recovered through PSO's SPPTC Tariff. There is no reasonable justification for

1 expanding the SPPTC Tariff to include third party Schedule 9 charges, since the majority  
2 of such charges come from OK Transco and other PSO affiliates, and since the  
3 forecasted year-to-year variation in such charges over the next several years is relatively  
4 modest and consistent with variances (both increases and decreases) that are experienced  
5 in other costs and revenues recovered in base rates. Moreover, due to the numerous  
6 concerns described in my testimony, there is no justification for extending the existing  
7 SPPTC Tariff beyond this case. For these reasons, I recommend that the SPPTC be  
8 discontinued immediately and that appropriate adjustments be made to recover such  
9 costs through PSO's base rates.

10  
11 **Q: DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS IF THE SPPTC**  
12 **IS CONTINUED?**

13 A: Yes. In the event the SPPTC is continued, I recommend three primary changes to PSO's  
14 proposal. First, the costs recovered through the SPPTC should be limited to Schedule 11  
15 charges from parties who are not affiliated with PSO. This would require modifications  
16 to the existing SPPTC Tariff to eliminate the current provision for recovery of Schedule  
17 11 charges from SWEPCO and SW Transco. This recommendation reflects the higher  
18 standard which traditionally has been applied by the Commission to the recovery of  
19 affiliate costs and the inappropriateness of recovery of such costs through a rider  
20 mechanism. Second, I recommend that the third party Schedule 11 charges recovered  
21 through the SPPTC Tariff be limited to costs of transmission projects which are in  
22 service as of the date PSO files for an amendment to its SPPTC Tariff. This

1 recommendation will eliminate my concerns regarding the current use of forecasted costs  
2 for third party transmission costs in the current SPPTC Tariff, and is consistent with SPP  
3 transmission rider mechanisms which apply to PSO's AEP affiliates in Arkansas and  
4 Texas. My third recommendation is that future recovery of costs through PSO's SPPTC  
5 Tariff be further limited to the original approved budget of third party transmission  
6 projects reflected in Schedule 11 charges. This means that PSO would only recover the  
7 costs of projects that are actually in service and only up to the budgeted amount for these  
8 projects. My alternative recommendations to revise the existing SPPTC Tariff are  
9 reflected on my Exhibit MG-12.

#### **IV. B. PSO'S OTHER RIDERS**

10 **Q: IN ADDITION TO ITS REQUEST TO EXPAND THE SPPTC, DOES PSO**  
11 **PROPOSE ANOTHER NEW RIDER IN THIS PROCEEDING?**

12 **A:** Yes, PSO is seeking the Commission's approval to establish an Automated Metering  
13 Infrastructure Tariff (AMI Rider) which has a first year impact of \$7 million.

14  
15 **Q: HAS PSO MADE A SHOWING THAT ANY COMPELLING FINANCIAL**  
16 **REASON EXISTS TO JUSTIFY THE ADDITION OF THE AMI RIDER?**

17 **A:** No. PSO suggests that there may be customer benefits from investing in AMI  
18 equipment, but PSO does not explain why traditional rate recovery approaches will not  
19 allow them to make such investment. PSO could make its desired AMI investment and  
20 seek recovery in its next rate case. PSO has made it clear it expects to file a rate case in

1 2015 to include environmental compliance investment in base rates; thus, PSO would  
2 have the opportunity to include AMI investment in base rates in that proceeding as well.  
3 PSO has not shown any special circumstance or financial need for its AMI Rider and,  
4 therefore, the Commission should reject PSO's request for rider recovery of these costs.

5  
6 **Q: WHAT OTHER RIDERS DOES PSO REQUEST TO INCLUDE IN THIS**  
7 **PROCEEDING?**

8 A: In addition to the new AMI rider, PSO has seven existing revenue-generating or cost-  
9 recovery riders. PSO also uses a Tax Adjustment rider which allows it to collect taxes  
10 on the utility bills. PSO's seven cost-recovery riders, along with the estimated cost  
11 recovery amounts, are set forth below:

1	Fuel Cost Adjustment Rider (FA)	\$414,675,882
2	Purchased Power Capacity Rider (PPC)	\$1,559,781
3	Long-term Base Load Purchased Power Rider (BLPP)	\$126,676,581
4	Regulatory Assessment Fee Rider (RA)	\$1,800,903
5	Reliability Vegetation/Undergrounding Rider (RVU)	\$18,587,579
6	Demand Side Management Rider (DSM)	\$28,442,945
7	Southwest Power Pool Transmission Cost Tariff (SPPTC)	\$28,662,674
	Total estimated amount of PSO's current riders	\$620,406,345

12 Taken together, over \$600 million of PSO's approximately \$1.2 billion annual revenues  
13 are associated with these riders. Fuel and purchased power related costs make up \$542.9

1 million,<sup>5</sup> while the other \$77.4 million<sup>6</sup> relates to costs for non-fuel, normal O&M  
2 expenses. In other words, through its current and requested riders, PSO is seeking  
3 guaranteed recovery of more than one-half of its costs.

4 Also, this list demonstrates that all major aspects of PSO's operations are covered  
5 by its riders: Generation or Supply (FA, PPC, DSM, and BLPP), Transmission (SPPTC),  
6 and Distribution (RVU). That is, no substantial part of PSO's business is without the  
7 guarantee of some large amount of annual cost recovery. Stated another way, PSO's risk  
8 of not recovering its costs is reduced by 50 percent because of PSO's various riders.

9  
10 **Q: WHAT DOES THIS MEAN FOR PSO'S RATEPAYERS?**

11 **A:** In short, it means that ratepayers do not receive the full benefit of the regulatory model  
12 and bargain. As a result of these riders, PSO has little risk that it will not recover these  
13 costs. Under traditional regulation, PSO must manage its costs within the given revenue  
14 requirement and rates established during a rate case. After its rates are established in a  
15 rate case, PSO takes on the risk of managing and recovering its costs and earning a  
16 reasonable return. With the guaranteed cost recovery established through all of PSO's  
17 riders, the regulatory model has been almost completely changed in favor of PSO. The  
18 Company's risk of not earning a reasonable return has been significantly reduced.  
19 Meanwhile, ratepayers in effect guarantee PSO's rider-related costs whatever they are.

---

5 \$542.9 million in fuel-related costs are recovered through the first three riders listed above (FA + PPC + BLPP).  
6 \$77.4 million of non-fuel O&M costs would be recovered through the next four riders (RA + RVU + DSM +  
SPP).

1 In a competitive market, PSO would not be able to use surcharges; it would have to  
2 manage costs to remain competitive. With riders or surcharges, however, PSO has no  
3 such market discipline.

4  
5 **Q: DOES THE POSSIBILITY OF A PRUDENCE REVIEW SAFEGUARD**  
6 **RATEPAYERS REGARDING COST-RECOVERY THROUGH RIDERS?**

7 A: Not in a meaningful way. In my experience, the likelihood of a prudence review and  
8 subsequent disallowance of rider-associated costs is virtually non-existent. Only in the  
9 most egregious cases of imprudence are Commissions inclined to disallow costs.  
10 Moreover, Staff and others simply do not have the time and resources to engage in  
11 ongoing and in-depth prudence reviews. In short, prudence reviews are meant to  
12 enhance, not replace, the regulatory paradigm of setting rates through periodic rate cases.  
13 In light of the shift in risk associated with PSO's cost recovery riders, and given the  
14 breadth and scope of revenues associated with PSO's riders, if the Commission allows  
15 the riders to continue, it would be appropriate for the Commission to lower the  
16 Company's return on equity to reflect this significant change in risk.

17  
18 **Q: IN YOUR VIEW, ARE PSO'S RIDERS DESIGNED TO ELIMINATE THE**  
19 **COMPANY'S RISK OF NON-RECOVERY?**

20 A: Yes. PSO riders almost completely eliminate the Company's risks of non-recovery.  
21 First, and most importantly, this is accomplished by the true-up mechanism. This means,  
22 of course, that no matter what the costs are for a cost category being recovered through a

1 particular rider, PSO has no risk—zero risk—that its costs will not be recovered. With a  
2 true-up mechanism and guaranteed recovery, there is a significantly reduced incentive  
3 for PSO to control its costs. PSO has a much greater incentive to control and manage  
4 costs recovered through base rates than it does for costs recovered through riders with  
5 guaranteed recovery.

6 A second design feature of PSO’s riders is that they do not have a time limit—  
7 they are permanent in nature. This feature further shifts the risk of no-recovery from the  
8 Company to the ratepayers. Finally, PSO’s riders completely eliminate regulatory lag.  
9 Because the rider factors are based on estimated or anticipated costs with a true up, there  
10 is absolutely no delay in PSO recovering its costs. All of these features work together to  
11 eliminate the Company’s risk of non-recovery.

12  
13 **Q: IS THIS WIDESPREAD SHIFTING OF RISK IN FAVOR OF UTILITY**  
14 **COMPANIES THE TRADITIONAL PURPOSE OF RIDERS?**

15 A: No. According to the National Regulatory Research Institute’s (NRRI) white paper  
16 published in 2009,<sup>7</sup> public utility commissions traditionally approve riders only under  
17 “extraordinary circumstances.” Commissions consider cost trackers an exception to the  
18 general rule for cost recovery, and place the burden on a utility to demonstrate why  
19 certain costs require special treatment. According to the NRRI, the circumstances  
20 typically required for approval of riders occur when costs are:

- 21 (1) Largely outside the control of a utility;  
22 (2) Unpredictable and volatile;  
23 (3) Substantial and recurring; *and*

---

7 Costello, Ken, NRRI, “How Should Regulators View Cost Trackers?” published in September 2009.

1 (4) Causing severe financial consequences to the company.

2  
3 Based on these criteria, fuel costs historically have been viewed as good candidates for  
4 rider recovery because fuel cost levels are largely beyond the utility's control, volatile  
5 and significant in size. A second example may be major storm-related expenses.  
6 Typically, those costs are incurred to restore power after a major weather occurrence or  
7 storm. As such, they are considered emergency costs largely outside of the control of the  
8 utility and significant in size, and the rider recovery enables utilities to expedite storm  
9 recovery.

10  
11 **Q: DO YOU AGREE WITH THE NRRI CRITERIA?**

12 A: Yes. I agree that these are the appropriate criteria to apply when evaluating a utility's  
13 request for rider treatment.<sup>8</sup>

14  
15 **Q: WHY IS IT IMPORTANT THAT A UTILITY DEMONSTRATE SEVERE**  
16 **FINANCIAL CONSEQUENCES OR HARDSHIP TO JUSTIFY RIDER**  
17 **RECOVERY?**

18 A: It is widely recognized that riders reduce a utility's incentive to control its costs. For this  
19 reason, commissions reserve rider recovery for *extreme* or *special* circumstances where  
20 there is a substantial risk to the financial health of the utility. In this case, PSO has made  
21 no showing that special circumstances exist or that the PSO would suffer financial

---

<sup>8</sup> Different criteria would apply for a ratepayer request for rider treatment in a situation where a particular significant cost was declining year after year and the savings should be flowed back to ratepayers. To avoid having a rate case each year, rider treatment would be appropriate. A good example would be the sharp scheduled decline

1 distress without on-going recovery through many of its riders. With the exception of  
2 perhaps fuel costs, none of the riders PSO has requested meet the NRRI criteria. With  
3 request to its requested riders, PSO has failed to show that traditional ratemaking— that  
4 is, addressing these costs through general rate case recovery—would cause PSO any  
5 financial distress. Certainly, it may be more difficult for PSO to manage its costs  
6 between rate cases without guaranteed rider recovery, but that is not a sufficient reason  
7 to justify PSO’s requests. Indeed, providing a utility the incentive to manage its costs  
8 between rate cases is one of the key advantages of the regulatory model. This is why  
9 most regulators have favored adjusting rates between rate cases *only* when such  
10 adjustments avoid serious financial hardship for utilities. Specifically, the NRRI  
11 explains:

12 If a commission wants to guarantee that the utility will recover its  
13 authorized earnings, it would favor a rate design that allows the  
14 utility to recover all of its fixed costs in a monthly service charge  
15 or customer charge. Since generally commissions do not, they  
16 implicitly recognize the positive incentive effect from allowing a  
17 utility’s actual rate of return to deviate from the authorized level.  
18 Commissions also know that if a utility is continuously earning  
19 below its authorized rate of return, the utility has the right to file a  
20 general rate increase.<sup>9</sup>

21  
22 In this case, PSO’s testimony seems to indicate that it currently does not have a financial  
23 issue, but only that it may face potential future cost increases. Such speculation does not  
24 demonstrate financial distress or financial hardship. In the future, even if certain costs  
25 increase, other costs may go down or be eliminated entirely through efficiencies. It is  
26 not enough to simply say a particular cost category is expected to increase in the future,

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in OG&E’s QF contracts in the final years of the contracts. The Commission set up a rider to flow these savings back to ratepayers.

1 and therefore a rider is deserved or appropriate. This is a quintessential example of the  
2 problems associated with single-issue ratemaking. While single issue ratemaking may  
3 be reasonable for certain extreme or special circumstances — such as volatile fuel costs  
4 and emergency storm-recovery — single issue ratemaking is not appropriate to the  
5 extent PSO has requested in this case. PSO has not shown that its financial health would  
6 be jeopardized if non-fuel related riders are discontinued.

7  
8 **Q: WHAT DOES OIEC RECOMMEND?**

9 A: OIEC recommends that the Commission should deny PSO's requests to add new riders  
10 or expand existing riders. Moreover, OIEC urges the Commission to restore the  
11 traditional ratemaking paradigm with respect to PSO's non-fuel related costs currently  
12 receiving rider recovery. These routine O&M costs do not warrant rider-recovery  
13 treatment, neither is rider treatment justified under PSO's current financial  
14 circumstances. These costs are not largely outside management's control; moreover,  
15 they are not particularly volatile, substantial or recurring. There has been no showing  
16 that elimination of some or all of these riders would cause severe financial consequences  
17 to the Company.

18  
19 **Q: WHICH OF PSO'S RIDERS DO YOU BELIEVE SHOULD BE ELIMINATED?**

20 A: I propose that the Commission should eliminate rider recovery for the following items:

Reliability Vegetation/Undergrounding Rider (RVU)	\$18,587,579
Demand Side Management Rider (DSM)	\$28,442,945

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9 Id. at page 11.

Southwest Power Pool Transmission Cost Tariff (SPPTC)	\$28,662,674
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1 By restoring traditional rate treatment for these costs, the Commission will not impair  
2 PSO's ability to manage its costs. To the contrary, if these costs were recovered through  
3 base rates rather than through PSO's currently inflated system of riders, PSO would have  
4 much more incentive to lower its costs, keep the savings between rate cases, and provide  
5 the resulting dividends to its shareholder.

6  
7 **Q: DOES OIEC HAVE ANY OTHER RECOMMENDATIONS REGARDING PSO'S**  
8 **RIDERS?**

9 **A:** Yes. OIEC requests two modifications to PSO's Fuel Adjustment Rider process.  
10 Because such a large amount of PSO's revenues are associated with its fuel and  
11 purchased power costs and its Fuel Adjustment Rider, and because for some large  
12 industrial customers fuel and purchased power costs account for 50 percent or more of  
13 their total bill, OIEC requests that it, and any others who would like to participate, be  
14 afforded the opportunity to participate in PSO's annual fuel factor setting process.

15 Under the current process, PSO's annual fuel factor is established through  
16 Commission Staff review of an administrative PSO submittal seeking approval to change  
17 the annual fuel factor. Other parties are currently not participants in the annual fuel  
18 factor review and approval process. Pursuant to Title 17 O.S. § 253 (C), the  
19 Commission has the authority to hold an administrative proceeding on the establishment  
20 of fuel factors. Given the large amount of costs and revenues associated with PSO's fuel  
21 and purchased power and the Fuel Adjustment Rider, OIEC requests that the

1 Commission require administrative proceedings for PSO's annual Fuel Adjustment  
2 factors determination and approval. This would allow customers who are significantly  
3 impacted by the fuel factors to have some opportunity to review the information on  
4 which the factors are based. This is particularly important since PSO's annual factors  
5 are based on forecasted fuel and purchased power costs. Forecasted fuel costs are  
6 especially subjective and the more scrutiny of those forecasts, all other things being  
7 equal, the better.

8  
9 **Q: DO YOU HAVE ANY OTHER RECOMMENDATIONS CONCERNING THE**  
10 **FUEL ADJUSTMENT CLAUSE?**

11 A: Under PSO's existing Fuel Cost Adjustment (FCA) Rider, 75% of the margins earned  
12 from off-system sales are currently credited to customers as an offset to eligible fuel and  
13 purchased power expenses.

14  
15 **Q. HOW SHOULD MARGINS EARNED FROM PSO'S SALES INTO THE SPP'S**  
16 **NEW INTEGRATED MARKET ("IM") BE TREATED?**

17 A. PSO's customers have paid (and will continue to pay) significant costs for SPP high  
18 voltage transmission facilities and SPP administrative charges to allow PSO to  
19 participate in the new market. Under this new market, SPP will decide when PSO's  
20 generating units will supply energy to other parties in the market and will develop the  
21 accounting and billing records to facilitate the physical and financial accounting for such  
22 transactions. Under this new market structure, it is no longer necessary to provide PSO

1 with a financial incentive to encourage it to make off-system sales. For these reasons,  
2 100% of any future margins from PSO energy sales in the new SPP IM should be  
3 credited to customers and the Company's Fuel Cost Adjustment Rider should be  
4 modified to reflect this change.

5  
6 **V. AMENDMENT OF AEP WEST OPERATING AGREEMENT**

7 **Q: WHAT IS THE ISSUE REGARDING AEP'S RECENT DECISION TO AMEND**  
8 **THE AEP WEST OPERATING AGREEMENT?**

9 A: On October 1, 2013, AEP filed an application with the FERC in Docket Nos. ER14-8-  
10 000 and ER 14-9-000 seeking approval of proposed amendments to the AEP West  
11 Operating Agreement. (See Exhibit MG-8, PSO's response to OIEC 12-13.) According  
12 to the Company's Application with the FERC, the proposed amendments to the AEP  
13 West Operating agreements were necessary to align the agreement with SPP's revised  
14 operations under the new Integrated Market ("IM"). Under the revised Operating  
15 Agreement, which was accepted by the FERC to be placed into effect March 1, 2014,  
16 Internal Economy Energy transactions between PSO and SWEPCO no longer take place.  
17 These economy transactions between PSO and SWEPCO have been replaced by  
18 individual company sales and purchases in the SPP IM.

19  
20 **Q: DID PSO NOTIFY THE COMMISSION OF ITS PLAN TO AMEND THE AEP**  
21 **WEST OPERATING AGREEMENT TO ELIMINATE PSO'S RIGHTS UNDER**

1           **THE AGREEMENT TO MAKE ECONOMY ENERGY TRANSACTIONS WITH**  
2           **SWEPCO?**

3   A:    Based on my review of the docket service lists for the FERC proceedings in which these  
4           amendments to the AEP West Operating Agreement were proposed, it does not appear  
5           that the OCC was notified of these changes.

6  
7   **Q:    WAS THIS ISSUE DISCUSSED IN PSO'S TESTIMONY IN THIS CASE OR IN**  
8           **THE COMPANY'S MOST RECENT FUEL PRUDENCE PROCEEDING?**

9   A:    No. This significant change to the AEP West Operating agreement was not mentioned in  
10          the Company's testimony in this case, nor was it mentioned in the Company's testimony  
11          in PSO's most recent fuel prudence proceeding (Cause No. PUD 201300128), which was  
12          filed on October 8, 2013, shortly after AEP's application to amend the AEP West  
13          Operating Agreement was filed with the FERC.

14  
15   **Q:    DID PSO ADDRESS THESE PROPOSED AMENDMENTS TO THE AEP WEST**  
16          **OPERATING AGREEMENT IN ITS 2013 FUEL SUPPLY PORTFOLIO AND**  
17          **RISK MANAGEMENT PLAN?**

18   A:    No. Although the amendments to the AEP West Operating Agreement constituted a  
19          very significant change to PSO's historical practice of purchasing economy energy from  
20          SWEPCO, the amendments were not addressed in the Company's 2013 Fuel Supply  
21          Portfolio and Risk Management Plan.

1 **Q: WHAT IS THE IMPACT OF THE AEP WEST OPERATING AGREEMENT**  
2 **AMENDMENTS ON PSO'S OKLAHOMA CUSTOMERS?**

3 A: While PSO asserts that the Company will realize additional benefits from energy  
4 purchases and sales into the SPP IM, it has not quantified the associated replacement  
5 energy cost arising from AEP's decision to amend the AEP West Operating to  
6 discontinue economy energy transactions between PSO and SWEPCO. (See Exhibit  
7 MG-9, PSO's response to OIEC 12-13)

8  
9 **Q: DID AEP ADDRESS THE ESTIMATED RATE IMPACTS OF THESE**  
10 **AMENDMENTS TO THE AEP WEST OPERATING AGREEMENT IN ITS**  
11 **FERC APPLICATION FOR APPROVAL OF THE AMENDMENTS?**

12 A: No. AEP requested and received a waiver of the filing requirements that address the rate  
13 impacts of the proposed amendments to the AEP West Operating Agreement in its  
14 application to the FERC for approval of the amendments. Therefore, the rate impacts of  
15 the AEP West Operating Agreement amendments on PSO and its Oklahoma customers  
16 were not considered by the FERC.

17  
18 **Q: HAS PSO PREVIOUSLY ADDRESSED THE BENEFITS TO OKLAHOMA**  
19 **CUSTOMERS OF ECONOMY ENERGY TRANSACTIONS UNDER THE AEP**  
20 **OPERATING AGREEMENT BEFORE IT WAS AMENDED?**

21 A: Yes. PSO has routinely addressed the benefits of the Company's affiliate economy  
22 energy transactions under the AEP West Operating Agreement and System Integration

1 Agreement in past annual fuel prudence filings with the OCC. According to direct  
2 testimony filed by PSO witness Naim Hakimi in past fuel prudence cases, the estimated  
3 fuel savings to Oklahoma customers produced from PSO's economy energy purchases  
4 under the AEP West Operating Agreement averaged approximately \$20 million per year  
5 over the most recent three (2010-2012) fuel prudence review periods. (See Exhibit MG-  
6 10.)

7  
8 **Q: HOW DO THE SAVINGS FROM PSO'S AFFILIATE ECONOMY ENERGY**  
9 **PURCHASES PRIOR TO THE AMENDMENTS TO THE AEP WEST**  
10 **OPERATING AGREEMENT COMPARE TO ESTIMATED BENEFITS FROM**  
11 **PSO'S PARTICIPATION IN SPP'S INTEGRATED MARKET?**

12 A: I am not aware of any recent estimates of the benefit to PSO's Oklahoma customers  
13 arising from the Company's participation in the SPP's IM. However, a July 2009 Study  
14 commissioned by SPP forecasted that the gross benefits to the AEP West Zone (PSO and  
15 SWEPCO) of participating in the new IM would be approximately \$30 million per year.  
16 (See Exhibit MG-11.) These previous SPP benefit estimates did not include the  
17 significant cost of implementing and administering the SPP IM, and they were based on  
18 forecasted natural gas prices in the range of \$7-\$10/MMBtu, which is far above current  
19 gas prices. Because one of the primary estimated benefits of participating in the IM was  
20 the ability of PSO and other parties to displace natural gas-fired energy with purchases  
21 of surplus coal-fired energy from other suppliers in SPP, and gas prices are now much  
22 lower than assumed in the SPP study, these previous estimates of IM benefits are greatly

1 inflated. This suggests that PSO's net benefit from participating in the IM market will  
2 probably be less \$10 million per year once adjusted to include costs of implementing the  
3 market and to reflect current natural gas prices. This suggests that PSO's customers may  
4 be paying significantly higher energy costs as a result of AEP's amendments to the AEP  
5 West Operating Agreement. Given the significant changes which have occurred since  
6 SPP's cost/benefit analysis for the IM market was conducted in 2009, AEP should have  
7 conducted an updated analysis to assess whether PSO's customers would in fact benefit  
8 from the amendments which eliminate PSO's rights to make economy energy purchases  
9 from SWEPCO under the AEP West Operating agreement.

10  
11 **Q: DOES PSO HAVE THE BURDEN TO DEMONSTRATE THE PRUDENCE OF**  
12 **ITS DECISIONS REGARDING FUEL AND PURCHASED POWER COSTS?**

13 A: Yes. The Commission's prudence review rules (OAC 165:35-35-1.(b)) specifies that:

14 All fuel and generation expenses, including purchased-power-related expenses,  
15 shall be reviewed by the Commission in adjudicatory proceedings to determine that  
16 such expenses were prudently incurred. The utility shall bear the burden of proof  
17 as to prudence. Additional prudence reviews shall be conducted when the  
18 Commission determines that circumstances warrant such review.

19  
20 **Q: WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?**

21 A: I recommend that the Commission order PSO to conduct production cost studies to  
22 assess the net replacement energy cost impact on PSO's Oklahoma customers arising  
23 from AEP's decision to amend the AEP West Operating Agreement to eliminate PSO's  
24 rights to purchase economy energy from SWEPCO, and present those results in the  
25 Company's next fuel prudence proceeding. This analysis should address reasonable

1 alternatives to the amendments, including continuation of economy purchases from  
2 SWEPCO under the AEP West Operating agreement both without and in conjunction  
3 with participation in the SPP's IM.  
4

## 5 **V. SUMMARY OF RECOMMENDATIONS**

6 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

7 A: My recommendations are set forth below:

8 **Change from 4CP to a 12 CP Allocation of Transmission Costs.** I recommend that  
9 the Commission reject PSO's requested change to a 12CP methodology and continue to  
10 use the 4CP methodology. The 4CP method reflects how retail customers actually use  
11 the system. The 4CP methodology has been used since 1996 by PSO and is used by  
12 OG&E as well. The 4CP is required in both Arkansas and Texas for PSO's sister  
13 company SWEPCO.

14  
15 **RTP Revenue Attribution Error.** PSO miscalculates revenues attributable to  
16 customers using the RTP program by including only revenues up to the customer base  
17 line ("CBL") in the cost of service study. PSO fails to include RTP revenues purchased  
18 above the CBL during the test year. This omission understates both LPL sales and  
19 revenues. My adjustment adds back the kWh purchased above the CBL and the  
20 associated revenues.

21  
22 **Industrial Class Revenue Attribution Errors.** PSO included a sharp increase in  
23 demand responsibility assigned to the LPL1 and LPL2 classes without a corresponding  
24 increase in revenues assigned to these classes. With the demand ratchet embedded in  
25 LPL rates, it is not possible to have an increase in demand without a corresponding  
26 increase in revenues. My adjustment accepts PSO's revenue allocation to the LPL  
27 classes but reduces the demand component down to the level supported by PSO's  
28 revenues to these classes.

29  
30 **Rate Design.** The Company's filed cost of service study is sufficiently flawed so as to  
31 render it unreliable as a basis for cost allocation to the classes. Although I found and  
32 corrected material errors in the industrial classes, I cannot say that the entire study, even  
33 with these corrections, is now sufficiently reliable. The corrected study also provides  
34 rate increases to some classes and rate decreases to others, which I am reluctant to  
35 recommend after only correcting the errors in the LPL classes. Therefore, I recommend  
36 that whatever rate increase or decrease is ultimately ordered in this case be spread to the  
37 classes on an equal percentage basis, meaning a 3.69% overall decrease, for example,

1 would result in a 3.69% decrease to each class. The same would be true for an increase,  
2 if one is ordered. It would be spread to the customer classes on an equal percentage  
3 basis.  
4

5 **SPPTC Rider.** PSO has not provided reasonable justification for expanding the SPPTC  
6 Tariff to include third party Schedule 9 charges. The majority of the Schedule 9 charges  
7 come from OK Transco and other PSO affiliates. The forecasted year-to-year variation in  
8 such charges over the next several years is relatively modest and consistent with  
9 variances (both increases and decreases) that are experienced in other costs and revenues  
10 recovered in base rates. Due to the numerous concerns described in my testimony, and  
11 because PSO demonstrates no special circumstances that justify extending the existing  
12 SPPTC Tariff beyond this case, I recommend that the SPPTC be discontinued  
13 immediately and that appropriate adjustments be made to recover such costs through  
14 PSO's base rates.  
15

16 In the alternative, in the event the SPPTC rider is continued, I recommend  
17 three primary changes to PSO's proposal. First, the costs recovered through the SPPTC  
18 should be limited to Schedule 11 charges from parties who are *not affiliated* with PSO.  
19 This would require modifications to the existing SPPTC Tariff to eliminate the current  
20 provision for recovery of Schedule 11 charges from SWEPCO and SW Transco.  
21 Second, I recommend that the third party Schedule 11 charges recovered through the  
22 SPPTC Tariff be limited to costs of transmission projects which are in service as of the  
23 date PSO files for an amendment to its SPPTC Tariff. This addresses the use of  
24 forecasted third party transmission costs in the current SPPTC Tariff, and is consistent  
25 with SPP transmission rider mechanisms which apply to PSO's AEP affiliates in  
26 Arkansas and Texas. Third, future recovery of costs through PSO's SPPTC Tariff  
27 should be limited to the original approved budget of third party transmission projects  
28 reflected in Schedule 11 charges. This means that PSO would only recover the costs of  
29 projects that are actually in service and only up to the budgeted amount for these  
30 projects.  
31

32  
33 **Other Riders.** OIEC recommends that the Commission deny PSO's requests to add  
34 new riders or expand existing riders. With respect to PSP's non-fuel related riders,  
35 OIEC recommends the Commission should restore the traditional ratemaking paradigm.  
36 Routine O&M costs do not warrant rider-recovery treatment, nor is rider treatment  
37 justified under PSO's current financial circumstances. These costs are not largely  
38 outside management's control; moreover, they are not particularly volatile, substantial or  
39 recurring. There has been no showing that elimination of some or all of these riders  
40 would cause severe financial consequences to the Company. I propose that the  
41 Commission should eliminate rider recovery for the following items: the Reliability  
42 Vegetation/Undergrounding Rider (RVU), the Demand Side Management Rider (DSM),  
43 and the Southwest Power Pool Transmission Cost Tariff (SPPTC).  
44

1 **Amendments to the AEP West Operating Agreement.** It appears that AEP amended  
2 the AEP West Operating Agreement to the detriment of Oklahoma ratepayers without  
3 informing the Oklahoma Corporation Commission. After March 1, 2014, pursuant to the  
4 AEP West Operating Agreement Amendment, Internal Economy Energy transactions  
5 between PSO and SWEPCO no longer take place. I recommend that the Commission  
6 order PSO to conduct production cost studies to assess the net replacement energy cost  
7 impact on PSO's Oklahoma customers arising from AEP's decision to amend the AEP  
8 West Operating Agreement to eliminate PSO's rights to purchase economy energy from  
9 SWEPCO, and present those results in the Company's next fuel prudence proceeding.  
10 This analysis should address reasonable alternatives to the amendments, including  
11 continuation of economy purchases from SWEPCO under the AEP West Operating  
12 agreement both without and in conjunction with participation in the SPP's IM.

13  
14 **Fuel Factor Changes.** OIEC requests that the Commission require administrative  
15 proceedings for PSO's annual Fuel Adjustment factors determination and approval. This  
16 would allow customers who are significantly impacted by the fuel factors to have some  
17 opportunity to review the information on which the factors are based. This is  
18 particularly important since PSO's annual factors are based on forecasted fuel and  
19 purchased power costs. Forecasted fuel costs are especially subjective and the more  
20 scrutiny of those forecasts, all other things being equal, the better.

21  
22 **Off-System Sales Margin Sharing.** PSO's customers have paid (and will continue to  
23 pay) significant costs for SPP high voltage transmission facilities and SPP administrative  
24 charges to allow PSO to participate in the new market. Under this new market, SPP will  
25 decide when PSO's generating units will supply energy to other parties in the market and  
26 will develop the accounting and billing records to facilitate the physical and financial  
27 accounting for such transactions. Under this new market structure, it is no longer  
28 necessary to provide PSO with a financial incentive to encourage it to make off-system  
29 sales. For these reasons, 100% of any future margins from PSO energy sales in the new  
30 SPP IM should be credited to customers and the Company's Fuel Cost Adjustment Rider  
31 should be modified to reflect this change.  
32

33 **Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

34 **A:** Yes. It does.