BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR COMMISSION AUTHORIZATION OF A PLAN AND COST RECOVERY OF ACTIONS OF PSO TO BE IN COMPLIANCE WITH CERTAIN ENVIRONMENTAL RULES PROMULGATED BY THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; SUCH ACTIVITIES TO INCLUDE, BUT NOT BE LIMITED TO, CAPITAL EXPENDITURES FOR EQUIPMENT AND FACILITIES; CONSTRUCTION OR PURCHASE OF AN ELECTRIC GENERATING FACILITY OR ENTER INTO A LONG-TERM PURCHASE POWER CONTRACT (AND POSSIBLE EARNING ON THE CONTRACT); CHANGE IN DEPRECIATION RATES AND/OR ESTABLISHMENT AND RECOVERY OF A REGULATORY ASSET; AND FOR SUCH OTHER RELIEF AS THE COMMISSION DEEMS PSO IS ENTITLED.	CAUSE NO. PUD 201200054

SURREBUTTAL TESTIMONY
OF
MARK E. GARRETT

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

MARCH 22, 2013

Surrebuttal Testimony of Mark E. Garrett
March 22, 2013

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Mark Garrett. I am the President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation and consulting services.

Q: DID YOU PROVIDE RESPONSIVE TESTIMONY IN THIS PROCEEDING?

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

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

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

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: In my responsive testimony I addressed the following four areas:

(1) Rate Impacts of PSO's EPA Settlement Plan,

(2) Cost Recovery of PSO's Closed Northeastern Coal Units,

(3) Cost Allocation Issues Related to the EPA Settlement Plan, and

(4) Return on the Calpine Purchase Power Contract.

In this testimony I respond to the Company's rebuttal testimony in each of these areas.

II. RATE IMPACTS

Q: PLEASE PROVIDE AN OVERVIEW OF THE VARIOUS TESTIMONIES WITH RESPECT TO THE OVERALL RATE IMPACT OF PSO'S EPA SETTLEMENT PLAN.

A: In direct testimony, PSO witness Jones testified that the EPA settlement plan would result in an 11% first-year increase in rates in 2016.[1] However, Ms. Jones did not provide any forecasted revenue requirements or rate impacts of the EPA settlement plan beyond the first year implementation.

In responsive testimony, I testified that PSO's claimed 11% rate increase for the EPA plan was understated because PSO's calculations start with projected 2016 revenues and compare those to 2016 revenues with recovery of EPA compliance plan costs. I testified that the rate impact of PSO's plan should be measured against rates in effect when PSO <u>made the decision</u> to pursue the settlement plan, which would mean, at the very latest, against rates in effect in June 2012, when the Company chose to move ahead with its settlement plan rather than to avail itself of a Tenth Circuit stay.[2] When rates with settlement plan costs are compared with 2012 rates rather than 2016 rates, the EPA Settlement results in a 14.6% increase, not an 11% increase. I also testified that PSO's environmental compliance plan only replaces 260MW of the entire 460MWs retired at the Northeastern plant in 2016, with the 200MW deficiency in capacity to be absorbed by PSO's over-bought Exelon contract. If the 200MW deficiency were

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1 See Direct Testimony of Shauna G. Jones at page 6, lines 2-13, and Exhibit SGJ-1.
2 On June 22, 2012, the Tenth Circuit issued a stay of the SO2 requirements for OG&E's units until the court reaches a final decision on the merits of OG&E *et. al.'s* appeal. At that point in time, PSO could have also sought and received a stay from the Tenth Circuit, but instead chose to pursue the current Environmental Settlement Plan.

accounted for, the EPA settlement plan increase would be even higher. I also testified that by 2016, all of PSO's planned rate increases would result in a **44.8%** increase in rates.

In rebuttal testimony, Ms. Jones provided the following arguments in support of her direct testimony:

(1) Ms. Jones defended her 11% increase calculation and testifies that I should have included projected rider revenues,[3] projected fuel increases,[4] and projected load growth in my calculations.[5] Ms. Jones testified that when these projected 2016 revenues are included, the 11% calculation is correct.

(2) Ms. Jones testified that if my 2012 revenues are used as the starting point, Mr. Roach's calculation of the first year impacts of the retrofit option would still be higher than the settlement plan.[6]

(3) Ms. Jones also testified that none of the BLPP rider costs (Exelon contract costs) should be attributed to the Northeastern Unit 4 closure.[7]

(4) Ms. Jones did not dispute the fact that PSO's overall rates will increase by **44.8%** by 2016, if all of PSO's planned increases are allowed to take effect. She correctly points out that all of this increase is not attributable to the settlement plan.[8]

(5) Ms. Jones provided a chart that shows that PSO's current rates (at the time of her testimony) are 14.59% below the Oklahoma average and 21.6% below the regional

3 Shawnna Jones Rebuttal Testimony at page 7, line3 through page 8, line 7.
4 Shawnna Jones Rebuttal Testimony at page 8, lines 8 through 11.
5 Shawnna Jones Rebuttal Testimony at page 8, line8 through page 9, line 11.
6 Shawnna Jones Rebuttal Testimony at page 9, line20 through page 10, line 14.
7 Shawnna Jones Rebuttal Testimony at page12, line19 through page 13, line 5.
8 Shawnna Jones Rebuttal Testimony at page 12, lines 1 through 13.

average.[9]

Dr. Roach also addressed my rate impact testimony in his rebuttal testimony. With respect to the overall increase PSO has planned by 2016 of 44.8% he states:

> If correct, this is constructive as a back-drop for evaluation of a cost recovery proposal that will increase rates. However, to make a decision on cost recovery for the EPA Settlement it is best to focus only on the rate impacts of that decision alone.[10]

He goes on to say that the increase for the EPA Settlement decision should be evaluated against other options, and that when first-year increases are compared, the settlement option is the least cost.[11] He also admits, though, that the Company did not provide any revenue requirement calculations for any of the options beyond the first year.[12]

Surrebuttal to Ms. Jones

Q: **WITH RESPECT TO THE FIRST ARGUMENT, DO YOU HAVE ANY SURREBUTTAL?**

A: Yes. Ms. Jones' lengthy defense of her 11% increase calculation misses the point of my responsive testimony, (which may be my fault for not making the point better). Nevertheless, I do not disagree with the accuracy of her calculations. When compared with projected 2016 rates, rates which include implementation of the EPA Settlement are 11% higher. However, when compared with actual rates, when the decision was being made, rates following implementation of the EPA Settlement are 14.6% higher. I

9 Shawnna Jones Rebuttal Testimony at page 13, line6 through page 14, line 1.
10 Craig R. Roach Rebuttal Testimony at page 14, lines 20-23.
11 Id. at page 15, line 1 through page 16, line 4.
12 Id at page 16, lines 8-10.

merely make the point that, on their own, rates that include the settlement are 14.6% higher than rates in effect at the time of the decision. I do not think it is appropriate to make the percentage increase appear smaller than it really is by simply increasing the size of the denominator, by using higher projected revenues as the starting point. Both calculations are correct and both calculations provide useful information. It is important that the Commission understand the ramifications of PSO's compliance plan on ratepayers. It is also important to note that Ms. Jones does not disagree with the accuracy of the 14.6% rate increase calculation.[13]

Q: WITH RESPECT TO THE SECOND ARGUMENT, DO YOU HAVE ANY SURREBUTTAL?

A: Yes. Ms. Jones testified that if my 2012 revenues are used as the starting point, Mr. Roach's calculation of the first year impacts of the retrofit option would still be higher than the settlement plan.[14] In my opinion, Mr. Roach's first year impact calculations are not that helpful and, in fact, obscure the real economic impacts of these two options. Because the retrofit option is a *capital intensive* option, the initial impacts are high but they steadily decrease each year as the retrofit assets in rate base are recovered each month through depreciation expense. On the other hand, because the settlement plan, with its conversion to gas approach, is an *energy intensive* option, the costs of this option steadily increase over time as gas costs rise. For a real economic comparison of these

13 Ms. Jones does point that while the settlement plan costs are 14.6% higher than rates set in the last rate case, they are only 13.4% higher than rates in effect by July, 2012, because of increases in rider revenues that had occurred by then. (See Jones' Rebuttal Testimony at page 11).
14 Shawnna Jones Rebuttal Testimony at page 9, line20 through page 10, line 14.

two approaches one would have to compare the present values of the revenue requirement streams associated with each approach. This would provide a true overall cost comparison of each option. A first-year cost comparison is a fairly meaningless exercise.

Q: WITH RESPECT TO THE THIRD ARGUMENT, DO YOU HAVE ANY SURREBUTTAL?

A: Yes. In response to Ms. Jones testimony that none of the Exelon contract costs should be attributed to the Northeastern Unit 4 closure,[15] I would point out that I <u>did not</u> include any of the excess Exelon contract costs in the 14.6% rate impact calculation. I only said that in fairness, some amount of the over-bought Exelon contract should be attributed to the Northeastern Unit 4 plant closure. It is not possible to replace a 460MW unit with a 260MW contract. The other 200MW has to be accounted for, and it should come from the excess capacity in the Exelon contract. The Company says that the Exelon contract excess capacity is a sunk cost that ratepayers would have to absorb anyway, so it should not be counted against the Northeastern closure. But that is not really right. <u>But for</u> the Northeastern Unit 4 closure, the excess Exelon capacity could be sold into the market to offset the contract costs. These lost sales opportunities should be added to the settlement plan costs.

Q: WITH RESPECT TO THE FOURTH ARGUMENT, DO YOU HAVE ANY SURREBUTTAL TESTIMONY?

A: Yes. It is very important to note that Ms. Jones did not dispute the fact that PSO's overall rates will increase by **<u>44.8%</u>** by 2016 if all of PSO's planned increases are allowed to take effect.[16] In my opinion, a rate increase of this magnitude, over a short 3-year period, constitutes rate shock, will impose an undue hardship on PSO's customers and will cripple industrial development in Oklahoma. The 44.8% projected rate increase is not entirely attributed to the settlement plan, sidesteps an important issue in this case which is that such a large increase is on the horizon and could be devastating for PSO customers. It is noteworthy, though, that more than half of this increase would be avoided if the settlement plan were not approved.

Q: WITH RESPECT TO THE FIFTH ARGUMENT, DO YOU HAVE ANY SURREBUTTAL TESTIMONY?

A: Yes. Ms. Jones provided a chart in her rebuttal testimony that shows that PSO's current rates are 14.59% below the Oklahoma average and 21.6% below the regional average.[17] This testimony, however, requires further clarification and update. Ms. Jones' rate calculations were performed when PSO's over-all rates were abnormally low due to a refund to customers of over-collected fuel costs through the FCA. When PSO's <u>actual rates going forward</u> are used in determining PSO's rates, the comparison is much different. PSO's actual current rates are only 3.44% below the Oklahoma average and 8.25% below the regional average.[18] PSO's actual current <u>industrial</u> rates are right at

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15 Shawnna Jones Rebuttal Testimony at page12, line19 through page 13, line 5.
16 Shawnna Jones Rebuttal Testimony at page 12, lines 1 through 13.
17 Shawnna Jones Rebuttal Testimony at page 13, line6 through page 14, line 1.
18 See response to OIEC 21-7.

both the Oklahoma average and the regional average.[19] The comparisons get worse for PSO in 2016 after PSO's EPA Settlement Plan increases take effect. When PSO's own-projected revenues for 2016 are used in the calculations, PSO's rates are 15.44% above the Oklahoma average and 10.32% above the regional average.[20] On a more catastrophic note, when PSO's own-projected revenues for 2016 are used in the calculations, PSO's industrial rates are 21.14% above the Oklahoma average and 19.69% above the regional average.[21] These rates would be disastrous for Oklahoma's industrial sector.

The chart below shows the following rate comparisons: (1) the rate comparisons contained in Ms. Jones' rebuttal testimony, (2) these same rate comparison corrected for PSO's recent fuel factor increase and (3) these same rate comparison using PSO's own-projected 2016 revenues.

PSO Prices Compared to State and Regional Averages

	Total Rates		**Industrial Rates**	
	Oklahoma Avg	Regional Avg	Oklahoma Avg	Regional Avg
Jones' Rebuttal Testimony	14.59% Below	21.6% Below	15.05% Below	21.10% Below
Corrected Rates	3.99% Below	8.25% Below	0.74% Below	0.46% Below
2016 Projected Prices[22]	15.44% Above	10.32% Above	**21.14% Above**	**19.69% Above**

PSO's industrial rates are already at the state and regional averages. PSO's EPA Settlement Plan costs coupled with other planned rate increases by 2016 would make

19 See response to OIEC 21-7.
20 Response to OIEC 21-7 revised using PSO's projected 2016 revenues.
21 Response to OIEC 21-7 revised using PSO's projected 2016 revenues.
22 Obviously, with the 2016 comparisons, these percentages would change to the extent other utility rates either increase or decrease before then, and to the extent PSO's rates increase by more or less than the projected amounts.

Oklahoma's industrial rates non-competitive on a state and regional level, and, even though not shown here, on a national level as well.[23] At these prices, many manufacturing companies in PSO's service territory could leave the state as soon as feasibly possible and other companies thinking of moving to PSO's service territory in Oklahoma could decide not to do so.

Surrebuttal to Dr. Roach

Q: DO YOU HAVE ANY SURREBUTTAL TO DR. ROACH?

A: Yes. As I stated earlier, in response to my testimony showing that the overall rate increase projected by PSO for 2016 is 44.8%, Dr. Roach states:

> If correct, this is constructive as a back-drop for evaluation of a cost recovery proposal that will increase rates. However, to make a decision on cost recovery for the EPA Settlement it is best to focus only on the rate impacts of that decision alone.[24]

While I understand the point Dr. Roach is trying to make, I cannot agree that the Commission's review of PSO's environmental compliance plan should be made in a vacuum, without considering the circumstances in which PSO's decision to adopt such a plan is made. Business decisions are not made that way and this Commission should not make its decision without considering the overall rate impact that PSO's plan will have on customers in light of the other increases they will be asked to bear at the same time. Since any increase greater than 10% is generally considered rate shock, PSO's projected 11% increase in 2016 will constitute rate shock, while the 44.8% increase over the four-

23 With the projected 2016 increases, PSO's rates would be only 1.34% less than the national average.
24 Craig R. Roach Rebuttal Testimony at page 14, lines 20-23.

year period from 2012 to 2016 will constitute rate shock after rate shock four years in a row. If anyone believes these increases will NOT drive industrial load out of Oklahoma, they are mistaken.

Q: DO YOU HAVE OTHER SURREBUTTAL TO DR. ROACH?

A: Yes. Dr. Roach is critical of my testimony because I look only at the rate impacts of the settlement plan. He testifies that the increase for the EPA Settlement decision should be evaluated against other compliance options, and that when first-year increases are compared, the settlement option is the least cost.[25] He also admits, though, that the Company did not provide any revenue requirement calculations for any of the options beyond the first year.[26]

Q: DO YOU AGREE WITH THIS TESTIMONY?

A: No. Again, I understand the point that Dr. Roach is trying to make. However, I would first point out that my impact analysis was meant to evaluate what PSO chose to do, not what it chose not to do. But, with respect to using first year impacts alone to evaluate the Settlement Plan against other potential options, I cannot agree with Dr. Roach. A business decision of this magnitude should <u>not</u> be made based on first-year impacts alone. Dr. Roach admits that he did not consider revenue requirement impacts beyond 2016. And the Company admits that it did not even model revenue requirement impacts

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25 Id. at page 15, line 1 through page 16, line 4.
26 Id at page 16, lines 8-10.

over the life of the project.[27] This information would be essential information for making a decision to approve this plan.

By looking only at the first-year impacts, PSO and Dr. Roach ignore the higher long-term impacts of the settlement plan compared to the retrofit option. For example, the majority of the cost increases under the settlement are expected to occur when the second coal unit is retired. These significant increases are completely ignored by looking only at first-year impacts. Businesses do not make long-term decisions of this magnitude based on first year pricing alone.

Q: IS DR. ROACH CORRECT IN SAYING THAT THE FIRST YEAR IMPACTS OF THE EPA SETTLEMENT PLAN ARE LOWER THAN THE RETROFIT OPTION?

A: No. Dr. Roach is only correct in saying that PSO's first-year impact calculations reflect that the settlement is the lower-cost option in the first year of settlement implementation. According to PSO's analysis, the first year impact of the Settlement is an 11% increase while the first year impact of the retrofit option is a 12.9% increase. What this information does not show is that revenue requirements under the settlement plan will increase steadily as gas prices rise over time and will jump substantially in 2027 when the second coal unit is retired. In contrast, revenue requirements for the retrofit option will steadily decrease over time as the high initial capital balances decline each year from depreciation recoveries and ADIT increases. This is a comparison that must be made to evaluate these two options. Neither PSO nor Dr. Roach made this comparison.

27 See response to OIEC 21-5.

In addition, PSO's first year impact calculations are flawed for a couple of reasons.

First, PSO fails to reduce the cost impact of the retrofit option for sales revenues from the available excess capacity from the Exelon contract. In the settlement plan option, PSO uses this excess capacity to retire the Northeastern unit. In effect they retire 460MW and replace it with only 260MW from the Calpine contract. The 200MW difference comes from the excess capacity from the Exelon contract. In the retrofit option, this excess capacity is not accounted for and assigned no value. In reality, this excess capacity would be sold into the market. These opportunity sales would then be used to reduce the cost impact of the retrofit option . The first year value of these opportunity sales is approximately $21 million.[28] With these opportunity sales, the Retrofit Both Units option first-year impact decreases from $193M to $172M, which is very close to the $164M first-year EPA Settlement option increase. The percentage increase for the retrofit option becomes 11.4%, not 12.9%, which is much closer to the 11% increase for the settlement plan.

Further, PSO's first-year revenue requirement calculations for the retrofit option do not include the benefits of the 50% bonus depreciation rules. Although these rules are set to expire at the end of 2013, any assets placed in service by 2014 would qualify. Moreover, the rules could likely be extended for another year as they have been since 2008. If the bonus depreciation benefits were included in the revenue requirement calculations, the first year retrofit option would decrease by another $17.4M. The total decrease for bonus depreciation and opportunity sales would be $38.4M bringing the

28 Derived by dividing the annual Calpine capacity charge of $26.1M (Exh RWH-1) by the 260MW Calpine contract capacity and then multiplying this rate times 210MW. Calpine is used as the latest available PPA costs.

retrofit costs from $193M down to $155M. This would represent a first year cost increase of 10.4%, which would be lower than the settlement option.[29]

Q: DO YOU BELIEVE THESE TWO ITEMS SHOULD HAVE BEEN INCLUDED IN THE ANALYSIS?

A: With respect to the excess capacity, I believe the benefits of the excess capacity must be included in evaluating both options to make the comparison fair. PSO definitely skewed the results in favor of the settlement option by only including the benefits there. With respect to the bonus depreciation benefits, I agree it is appropriate to compare the two options without looking at these potential additional tax benefits, however, a prudent business decision would have taken the possibility of these potential benefits into consideration in its analysis.

In my opinion, the only way you could select the EPA settlement option would be to look only at first year impacts, and then it would only be possible if the first year impacts were improperly biased toward the settlement option, as they have been here.

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29 Bonus depreciation would drop the settlement plan increase to about 10.6%. The bonus depreciation rules have a much greater impact on the retrofit option because the retrofit option is so much more capital intensive.

III. <u>RECOVERY OF THE NORTHEASTERN UNIT 4 PLANT COSTS</u>

Q: PLEASE PROVIDE AN OVERVIEW OF WHERE THE ISSUES STAND WITH RESPECT TO PROPOSED RECOVERY OF THE CLOSED NORTHEASTERN UNIT 4 PLANT COSTS.

A: In my responsive testimony I said that PSO's plan to shut down 460MW at the Northeastern Unit 4 coal plant in the middle of its useful life but to continue to include both a "return on" and a "return of" the plant costs in rates was contrary to Oklahoma law that allows only "used and useful" plant to be included in rates. I said that faced with the same issue, the Ohio Commission *denied* AEP-Ohio Power's request for recovery of costs associated with the retirement of its Sporn 5 unit, a 450MW coal plant in Ohio. In its order dated January 11, 2012, the Ohio commission found that the retired plant did not meet the "used and useful" requirements in Ohio. I said that neither the EPA's regional haze FIP nor the SIP require such action. According to Mr. Norwood, the Company's own analysis shows that the nominal cost of the Retrofit Both Units option (keeping the assets in service) is approximately $2 billion <u>lower</u> than the cost of the EPA Settlement plan (taking the assets out of service). I said that I knew of no ratemaking theory that would require ratepayers to share the costs of retired assets, when such retirement is voluntary and results in higher, not lower, rates.

In rebuttal testimony, both Mr. Sartin and Mr. Hamlett address my recommendation to disallow recovery of the closed plant costs. Mr. Hamlett spends almost all of his rebuttal testimony explaining why the Company's accounting treatment of the closed plant costs (keeping them in rate base) is consistent with the Uniform

System of Accounts' ("USOA") prescribed accounting treatment. At page 3, lines 18-22, he states:

> Mr. Garrett makes many statements that do not comply with Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) and as such his recommendations are inappropriate and should be rejected by this Commission, whereas PSO's plan is in full compliance with the FERC USOA.

The message in his rebuttal testimony is that the Commission has no choice but to follow the standard accounting entries for retired plant and has no authority to order any disallowance, which is absolutely false.

Mr. Sartin, on the other hand, seems to understand, and admits indirectly, that the Commission does have the discretion to disallow the utility's cost recovery of prematurely retired plant. At page 20, lines 20-22, he states the following:

> Mr. Garrett indicates that PSO should not recover its costs of the Station because PSO voluntarily chooses to retire it, but his proposal would only be appropriate if PSO's Plan was not reasonable.

Q: DO YOU HAVE ANY SURREBUTTAL TO MR. HAMLETT'S TESTIMONY?

A: Yes. Mr. Hamlett's lengthy discussion of how closed plant costs are generally treated under the USOA seems to be meant to imply that, because the USOA treatment for standard retirements leaves the balance of the plant in rate base, commissions' hands are tied and they have no authority to disallow cost recovery of prematurely retired plant. This implication is false and misleading. Public utility commissions clearly have the authority to disallow cost recovery whenever they believe it to be appropriate.[30] If Mr. Hamlett's view of the world were accurate, utilities could simply abandon useful plant whenever they wanted to, and commissions would have no choice but to leave the costs in rates. This proposition is preposterous.

Even the Company's other witness on this issue, Mr. Sartin, does not agree with Mr. Hamlett's narrow view of the Commission's authority. At page 20 of his rebuttal testimony, Mr. Sartin admits disallowance and removal from rate base would be appropriate if the Company's plan were found to be unreasonable. Mr. Hamlett's narrow view of the Commission's authority is also undermined by the recent disallowance by the Ohio commission of the remaining costs of the retired Sporn 5 unit, a 450MW coal plant in Ohio. In its order dated January 11, 2012, the Ohio commission found that the retired plant did not meet the "used and useful" requirements in Ohio.

Q: WITH RESPECT TO MR. HAMLETT'S TESTIMONY STATING THAT YOU MAKE MANY STATEMENTS THAT DO NOT COMPLY WITH THE USOA AND AS SUCH YOUR RECOMMENDATIONS ARE INAPPROPRIATE AND SHOULD BE REJECTED BY THIS COMMISSION, DO YOU HAVE ANY SURREBUTTAL TESTIMONY?

A: Yes. All of the statements in my responsive testimony are completely consistent with regulatory law, which is what really matters, and more importantly, are consistent with this Commission's authority to decide issues of cost recovery. Moreover, my statements

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[30] In setting rates, the Commission may exclude unnecessary items of cost; expenses that are excessive, unwarranted or unreasonable, and items that are not "used or useful" to ratepayers. Public Service Company of

are also consistent with the USOA. In his description of the USOA, and in the portions of the USOA attached to his testimony, Mr. Hamlett conveniently leaves out the USOA description for account 182.2:

> **Account 182.2 Unrecovered plant and regulatory study costs.**
>
> A. This account shall include . . . <u>significant unrecovered costs of plant facilities</u> . . . which have been <u>prematurely retired</u>.
>
> D. In the event that the recovery of costs included herein <u>is disallowed in the rate proceeding</u>, the disallowed costs shall be charged to account 426.5, Other Deductions, or account 435, Extraordinary Deductions, in the year of such disallowance.

In other words, under the USOA, <u>disallowed plant costs are written off</u>, as I said in my testimony. They are not charged to accumulated depreciation, as Mr. Hamlett tries to imply.

Q: DO YOU HAVE ANY SURREBUTTAL TO MR. SARTIN'S TESTIMONY?

A: Yes. Mr. Sartin acknowledges that the Commission has the discretion to disallow cost recovery of prematurely retired plant. At page 20, lines 20-22, he states the following:

> Mr. Garrett indicates that PSO should not recover its costs of the Station because PSO voluntarily chooses to retire it, but his proposal would only be appropriate if PSO's Plan was not reasonable.

This testimony says that the Commission <u>can</u> disallow recovery of the remaining plant costs if PSO's plan is not a reasonable plan. I generally agree with Mr. Sartin's analysis. However, the Commission could also disallow the remaining plant costs if the Commission found that PSO's plan was a reasonable plan but only <u>if</u> the Company were

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Oklahoma v. Oklahoma Corporation, 1983 OK 124, ¶¶ 43-44, 688 P.2d 1274, 1281.

willing to absorb the remaining costs of its voluntarily retired plant.

Q: WHY WOULD THAT BE A REASONABLE PROPOSAL?

A: As I said in my responsive testimony, neither the FIP nor the SIP require that the Northeastern unit be retired. Furthermore, the Company's settlement with EPA is not final and the revised State Implementation Plan has not been provided and is subject to further review and processing by both ODEQ and the EPA. Moreover, the Company's own analysis shows that the nominal cost of the EPA Settlement plan option is approximately $2 billion <u>more expensive</u> than the cost to the Retrofit option. I know of no ratemaking theory that would require ratepayers to pay the costs of voluntarily retired assets, when such retirement results in higher, not lower, rates. However, the Commission could still find PSO's plan to be reasonable, provided the utility absorbed the costs of the prematurely abandoned plant. This would be justified since the Northeastern plant is in the middle of its useful life, when the plant is particularly economic from a ratemaking perspective.

Q: WHY DO YOU SAY THAT A PLANT IN THE MIDDLE OF ITS USEFUL LIFE IS PARTICULARLY ECONOMIC FROM A RATEMAKING PERSPECTIVE?

A: Unlike a home mortgage that is levelized over the life of the loan, utility plant is collected on a declining balance basis over the life of the plant. In other words, utility plant is very expensive when it first goes into service but as the balance in rate base steadily declines each year through depreciation recoveries the plant becomes more and more economic as time goes by. In very general terms, during the second half of a generating plant's life, the plant will be producing the same amount of electricity for nearly half the amount of fixed costs. That is why the Northeastern plant is so valuable to Oklahoma ratepayers right now. Oklahoma ratepayers have already paid the expensive years of this plant's life. Now that the plant is a low-cost plant, the utility wants to retire it, which makes no sense from a business perspective. Understandably, there may be environmental upgrades required, but the analysis shows that the upgrades are a much lower cost option. In a competitive environment, companies generally choose lower cost options in order to retain market share. In the regulated world, though, utilities can make bad business decisions because their market consists of captive customers. And, as larger customers leave the system, as they likely will in this case if PSO's plan is approved and implemented, the costs will simply be spread among the remaining customer base, causing their rates to rise even further. In the Commission's role as the surrogate for competition, it should not approve this plan as companies operating in a competitive environment would not choose this option. In fact, I know of no commission in any state that has approved the closure of a low cost, efficient coal plant in the middle of its useful life in response to EPA rules. Such action would amount to economic waste.

IV. COST ALLOCATION ISSUES

Q: PLEASE PROVIDE AN OVERVIEW OF WHERE THE ISSUE STANDS CONCERNING HOW THE COSTS OF PSO'S ENVIRONMENTAL COMPLIANCE PLAN, IF APPROVED, SHOULD BE ALLOCATED TO THE CUSTOMER CLASSES.

A: In my responsive testimony, I testified that while ordinarily I would agree that the capacity costs of the BLPP rider would be allocated using a production allocator and the energy costs would be allocated using an energy allocator, in light of the list of relevant factors set forth below, a different approach should be considered, in the event the Commission approves PSO's EPA settlement plan. These relevant facts include:

1. The EPA settlement plan is not the least cost option for ratepayers.

2. The majority of the higher costs of the EPA settlement plan are energy-related costs (gas prices compared with coal prices), meaning that the higher (uneconomic) costs of the plan fall disproportionately on the high-load-factor industrial customers, with an energy allocation factor.

3. There is a substantial amount of energy already embedded in the Company's production cost allocator.

I said that these facts taken together support a recommendation to allocate the costs of the BLPP rider using a production cost allocator only. I said that in doing so, the Commission would adopt an allocation to the industrial class that would more closely reflect the cost allocation that would result under the Retrofit Both Units approach.

In her rebuttal testimony, Ms. Jones spends several pages explaining why the BLPP Rider costs should be allocated using a combination of a demand cost and an energy cost allocation, which under ordinary circumstances, I would generally agree with. However, she does not address any of the relevant facts listed above that show this situation is not an ordinary situation. Further, at page 18, line 11, she makes the following statement: "However, Mr. Garrett's application to allocate all of the Calpine PPA costs on a demand allocator ignores the fact that the retrofit option is not simply the additional capital costs only, but to generate kWh, therefore PSO will incur energy allocated fuel and environmental costs."

Q: IS SHE CORRECT? DID YOU IGNORE THE FACT THAT THE RETROFIT OPTION IS NOT SIMPLY A CAPITAL COST OPTION BUT WILL HAVE ENERGY COSTS ASSOCIATED WITH IT AS WELL?

A: Absolutely not. The fact is, the energy costs associated with the retrofit option are energy costs that we are already incurring. As such, they are not incremental costs. The point of the impact analysis for each option is to show the incremental cost of following that option. Since we are already incurring the energy costs associated with the retrofit option they would not be included in a comparison of the incremental impacts of the two allocation methodologies.

Q: AFTER READING MS. JONES' REBUTTAL TESTIMONY, DO YOU STILL BELIEVE THAT YOUR PROPOSED ALLOCATION WOULD MORE CLOSELY REFLECT THE COSTS THE INDUSTRIAL CLASS WOULD HAVE RECEIVED UNDER THE RETROFIT APPROACH?

A: Yes. According to the class allocations provide by the Company in response to AG 3-

18, the first-year allocation to the SL2 class for the retrofit option would be $16.8M, while the first-year allocation for the EPA Settlement Plan would be $18.4M . If the EPA Settlement Plan were allocated using a production cost allocation, the first-year allocation to the SL2 class would be $14.2M. While the first-year allocation under the proposed approach ($14.2M) would be less than the first-year allocation for the retrofit option ($16.8M), you must consider that the annual costs of the retrofit option decrease each year over time as the retrofit plant costs depreciate, while the costs of the EPA Settlement increase over time as gas prices rise. The slightly lower allocation in year one will quickly turn around as gas prices increase over time. Also, PSO's revenue requirement calculation for the retrofit option does not include the potential benefits of the 50% bonus depreciation rules, which could be extended beyond 2013. If these tax benefits are extended, the first-year allocation to the SL2 class for the retrofit option would be around $15.2M, which is closer to the $14.2M that results under my proposed allocation, and supports my testimony that a production cost allocation of the BLPP Rider would more closely approximate the costs the industrial class would have received under a retrofit approach.

Q: ARE THERE OTHER REASONS TO APPROVE YOUR ALLOCATION?

A: Yes. If you look at the chart on page 10, industrial rates in 2016 will disproportionately exceed the Oklahoma and regional averages compared to other rate classes. My allocation would help alleviate this disparity and would help insure that the Commission's approval of the settlement plan would not penalize Oklahoma industry.

V. ADDITIONAL EARNINGS ON THE CALPINE CONTRACT

Q: PLEASE PROVIDE AN OVERVIEW OF WHERE THE ISSUES STAND SURROUNDING PSO's REQUEST TO EARN ADDITIONAL COMPENSATION ON THE CALPINE CONTRACT.

A: In my responsive testimony, I described how PSO is requesting that the Commission depart from the traditional ratemaking treatment for purchased power agreements (PPAs) to allow the Company to collect earnings associated with the Calpine Oneta, LLC contract ("Calpine Contract" or "Contract"), in the amount of $3 million annually.[31] PSO asserts that without these additional earnings, PSO will not be allowed to earn a return on a significant portion of its energy supply business.[32] In my responsive testimony, I explained that PSO's request – to be allowed to earn a return on *services* (i.e., fuel, purchased power, payroll, benefits, and other operating expenses) rather than on *invested capital* – is a radical departure from traditional ratemaking principles followed in Oklahoma and virtually every other jurisdiction. I explained that under current ratemaking jurisprudence and widely recognized regulatory policy, a utility is allowed to earn a reasonable return on its invested capital, not on operating expenses. I further explained that, PSO's request to earn a return on capital the Company did not invest, is contrary to fundamentally-accepted ratemaking principles (because it would provide a return where no capital has been invested), contrary to Oklahoma law (because it would cause an impermissible mark-up on purchased power), and contrary to sound public policy (because it would provide the utility with a financial incentive to not invest

[31] See Direct Testimony of Alan Decker at page 8.
[32] See Direct Testimony of Alan Decker at page 3, lines 1-6.

capital in Oklahoma).

In rebuttal to these opinions, Mr. Decker provided the following testimony:

(1) Mr. Decker testifies that the position taken by OIEC, Staff and the AG – that PSO should be required to provide services without earning anything for doing so – is an extreme position.[33] The Commission has a duty to provide PSO a reasonable level of overall earnings and PSO's earnings will be inadequate if it does not earn on all of the kWh it supplies to customers.[34]

(2) Mr. Decker testifies that the Calpine and Exelon contracts are not subject to the statutory prohibition against utilities collecting more than the actual cost for fuel and purchased power (17 O.S. §§ 250 through 257), because the fuel clause statutes pertain only to fuel and purchased power costs above and below the amounts included in base rates, and none of the Exelon or Calpine costs are included in base rates.[35]

Q: WITH RESPECT TO THE FIRST ARGUMENT, DO YOU HAVE ANY SURREBUTTAL TESTIMONY?

A: Yes. Mr. Decker's characterization of the OIEC, AG and Staff position – that PSO should be required to provide services without earning anything for doing so – as an extreme position, is a mischaracterization of that position. The position taken by OIEC, Staff and the AG is not an extreme position, in fact, it is the exact position taken by virtually every regulatory commission in every state for more than a hundred years now. Regulated utilities are allowed to earn a return on invested capital, not on services

[33] Rebuttal Testimony of Alan Decker at page 3, line 19 through page 4 line 8.
[34] Rebuttal Testimony of Alan Decker at page 5, lines 21-23.

provided. Operating expenses such as fuel expense, purchased power expense, payroll expense, employee benefits expense, operating and maintenance expense, and tax expense, are all recovered at cost with no additional mark up. A utility's earnings come from its authorized return on invested capital (i.e. rate base).[36] The extreme position, clearly, is the position taken by the Company, where the utility would be allowed to earn a return on an expense - purchased power – an expense, no less, where additional compensation has been statutorily prohibited. That is the extreme position. The Company's request is not made less extreme by mischaracterizing the traditional, and lawful, approach as extreme.

To show how unusual the Company's request actually is, the Garrett Group conducted a survey, in 2012, of the twenty-four (24) western states to understand how purchased power contracts are treated for ratemaking purposes in each of these states, and to ascertain which states, if any, allow additional compensation above cost on purchased power contracts. Of the twenty-two states that responded to our survey, no state provides additional compensation above cost for PPAs. While it is very common for utilities to provide a portion of their retail sales through PPAs, no utility receives additional compensation on these contract costs.

Q: CONCERNING THE SECOND PART OF THE FIRST ARGUMENT, THAT THE COMMISSION HAS A DUTY TO PROVIDE PSO A REASONABLE

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[35] See Rebuttal Testimony of Alan Decker at page 9, line 1 through page 10, line 2.

[36] A utility can also make and lose money on regulatory lag changes, in effect, the increases and decrease in expense levels between rate cases, except for changes in fuel and purchased power expenses which are trued-up through a rider mechanism, which relieves the utility of the collection risk associated with these costs.

LEVEL OF OVERALL EARNINGS AND PSO'S EARNINGS WILL BE INADEQUATE IF IT DOES NOT EARN ON ALL OF THE KWH IT SUPPLIES TO CUSTOMERS. DO YOU HAVE ANY SURREBUTTAL?

A: Yes. The statement is false and the conclusion he draws from that false statement is incorrect. The statement is false because the Commission <u>does not</u> provide PSO reasonable overall earnings; the Commission provides PSO with an opportunity to earn a reasonable return on capital prudently invested for the provision of electric service. The conclusion he draws is incorrect because PSO's earnings on invested capital are not diminished by the fact that PSO is not provided an additional return on an operating expense, purchased power. Many utilities rely on purchased power contracts to provide electric sales and still have adequate earnings because earnings are evaluated based on invested capital, not retail sales volumes. For example, in restructured states, all of the utilities' generation is provided through purchased contracts and these utilities still have adequate earnings, because their earnings are evaluated based on the amount of capital they have invested in transmission and distributions assets. Further, many fully integrated utilities provide a substantial portion of their retail sales through purchased power contracts and yet their earnings are adequate because earnings are evaluated based on invested capital, not retail sales. For example, OG&E's 2012 Form 10-K reports that OG&E currently purchases about 17% of its retail sales volumes. OG&E has provided a substantial portion of its retail sales through two purchase power contracts from the Power Smith and Shady Point plants for more than 20 years now, and OG&E's earnings have been strong throughout these years.

Q: WITH RESPECT TO THE SECOND ARGUMENT, DO YOU HAVE ANY SURREBUTTAL TESTIMONY?

A: Yes. Mr. Decker testifies that the Calpine and Exelon contracts are not subject to the statutory prohibition against utilities collecting more than the actual cost for fuel and purchased power found in the fuel clause statutes at 17 O.S. §§ 250 through 257, because the fuel clause statutes pertain only to fuel and purchased power costs above and below the amounts included in base rates, and since none of the Exelon or Calpine costs are included in base rates, the statute does not apply to these contracts.[37]

This argument certainly defies the imagination. Taken to its logical conclusion, this argument suggests that if the level of fuel and purchased power costs in base rates were set to zero, and all of the costs were collected through a rider, then the statute would not apply and a mark-up on fuel and purchased power costs would be permissible. Clearly, that is not the case. The "at cost" requirements of the fuel clause statutes cannot be avoided by simply setting the amount recovered in base rates to zero and recovering all of the cost through a rider. Zero is an amount. In fact, zero is the amount used by the other major electric utility in this state, OG&E. Currently, OG&E recovers all of its fuel and purchased power costs through the fuel rider, and the amount included in base rates is zero, but OG&E is not allowed, and is not requesting to be allowed, to mark-up its fuel or purchased power contracts above costs, or earn a return on these contracts or be provided with additional compensation in any form on it fuel and purchased costs.

Q: WHAT LANGUAGE FROM THE STATUTE DOES MR. DECKER CITE FOR HIS PROPOSITION THAT THE FUEL CLAUSE STATUTES DO NOT APPLY TO THIS CONTRACT BECAUSE NO PORTION OF THE CONTRACT IS BEING COLLECTED THROUGH BASE RATES?

A: Mr. Decker cites 17 O.S. 250.

> . . . any mechanism which allows a public utility or electric generating cooperative to automatically adjust its charges above or below the base amount included in its rates, based upon changes in costs of fuel for generation of electricity, purchased power, or purchased gas. (Emphasis added).

Using this language, Mr. Decker provides the following testimony at page 9, lines 25-28:

> Rather than collect costs associated with changes in costs from base rates, the BLPP Tariff allows PSO to recover the total, actual costs of the Exelon contract – not just the change in costs from base rates. PSO's BLPP tariff was not designed to nor does it meet the statutory definition of a fuel adjustment clause, and thus Mr. Garrett's argument on this point is not valid, and PSO can (should the Commission authorize it to) collect earnings on the Calpine contract through the BLPP Tariff.

This testimony says that the fuel clause statutes do not apply to the BLPP rider because all of the PPA costs are being collected through the rider and none of the costs are being collected in base rates. Under Mr. Decker's interpretation of the statute, the fuel clause statutes would not apply to any fuel and purchased power costs if all of the costs were collected through the rider and not through base rates. Clearly, Mr. Decker's legal analysis is wrong. The statute refers to "any mechanism" which would include the BLPP rider. And clearly, the amount included in base rates could easily be zero, as it is with OG&E's Fuel Clause Adjustment rider.

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[37] See Rebuttal Testimony of Alan Decker at page 9, line 1 through page 10, line 2.

Q: DOES PSO PROVIDE ANY OTHER REBUTTAL TO YOUR TESTIMONY THAT A RETURN ON PURCHASED POWER CONTRACTS IS CURRENTLY PROHIBITED BY LAW IN OKLAHOMA?

A: No. In my responsive testimony I stated that in Oklahoma, Commission rules and statutes explicitly prescribe that purchase power contracts must be recovered ***at actual cost***, without the mark-up PSO seeks. The Commission's rules for cost recovery for purchased power reflect the statutory requirements set forth in 17 Okl.St.Ann. § 252:

Title 17 § 252. Monitoring of fuel adjustment clauses.

> Whenever the Commission approves a fuel adjustment clause pursuant to this act, the clause shall apply to all similar public utilities affected by such increased costs. In addition, the Commission shall continually monitor and oversee the application of the fuel adjustment clauses. The Commission shall hold a public hearing thereon whenever it deems it necessary, but no less frequently than once every twelve (12) months. If the Commission finds that the charges or credits are not based upon the **actual prices paid for** fuel, purchased gas or **purchased power**, or are not properly computed in accordance with the applicable adjustment clause, it shall recompute the charges or credits and shall direct the public utility to take such action as may be required to insure that the charges or credits properly reflect the **actual prices paid** for fuel, purchased gas or purchased power and are properly computed in accordance with the applicable adjustment clause for the applicable period.

I further stated that the statutory requirements are clear: fuel and purchased power contracts must be recovered at cost, or more specifically, at the actual price paid for the fuel and purchased power contract. In short, the Company's request for a mark-up or additional earnings on the Calpine Contract is prohibited under Oklahoma law.

The Company's only rebuttal to this testimony is the rebuttal testimony of Mr.

Decker discussed above, where he says the fuel clause adjustment statutes do not apply to the Calpine contract because all of the costs are collected through the rider and not through base rates. Since this position is clearly wrong from a legal perspective, in my opinion, the Company has provided no credible rebuttal to the testimony that a return on purchased power contracts is currently prohibited under Oklahoma law.

Q: ARE THERE OTHER POSITIONS TAKEN IN YOUR RESPONSIVE TESTIMONY REGARDING THE REQUESTED RETURN ON THE CALPINE CONTRACT THAT THE COMPANY FAILED TO REBUT?

A: Yes. The Company failed to rebut any of the following propositions contained in my responsive testimony:

1. PSO's claim that federal and state policies caused PSO to buy rather than build is unsupported. PSO not only provides no support for this claim but also provides no explanation as to why other utilities operating under identical rules in this state and similar rules in other states are able to add assets to rate base at market-competitive prices. PSO also fails to explain why it chose <u>not</u> to submit a *self-build* bid option in the RFP process for this capacity, but instead chose to merely complain about the results of the bid process later.

2. PSO provided no example of a state that follows its recommendation. PSO identified Georgia as a state that allows additional compensation on PPAs. However, the return allowed in Georgia is authorized <u>by statute</u> and is <u>10 times smaller</u> by comparison than the return requested by PSO.

3. PSO's requested return is contrary to constitutional requirements. Oklahoma and virtually every other state follow the *prudent-investment rule* (or *original-cost rule)* where a regulated utility's Fifth and Fourteenth Amendment rights are satisfied when the utility is allowed to earn a return on the original cost of assets prudently invested for the provision of utility service. Here, PSO has invested no capital in the Calpine Contract and is therefore, not entitled to earn a return on the contract.

4. PSO's requested return is inconsistent with the treatment in other states. A survey of the 24 western states found no state that actually provides additional compensation on purchased power contracts.

5. PSO's requested return is contrary to sound public policy. From a policy perspective, it would be inappropriate for the Commission to compensate a utility "as if" it had invested capital in the state when in reality it had made no such investment. This approach would actually provide the utility with a disincentive to invest in Oklahoma.

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

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