BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES AND THE ELECTRIC SERVICE RULES, REGULATIONS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	Cause No. PUD 201700151 ORDER NO. 672864

HEARINGS: October 30-31, November 1-3 and 6-9, 2017, in Room 301, 2101 N. Lincoln Blvd., Oklahoma City, Oklahoma 73105 *before* Mary Candler, Administrative Law Judge

January 4, 2018, Hearing on Motions for Oral Argument and Exceptions to the Report of the Administrative Law Judge *before* the Commission in Room 301

APPEARANCES: Jack P. Fite, Joann S. Worthington, and Kendall Parrish, Attorneys *representing* Public Service Company of Oklahoma

Dara Derryberry, Katy Boren, Jared Haines, Chase Snodgrass, Assistant Attorneys General, *representing* the Office of the Attorney General, State of Oklahoma

Judith L. Johnson and Natasha Scott, Deputy General Counsels, Michael Velez, Lauren Hensley, and Olivia Waldkoetter, Assistant General Counsels, *representing* the Public Utility Division, Oklahoma Corporation Commission

Thomas P. Schroedter, Attorney, *representing* Oklahoma Industrial Energy Consumers

Deborah Thompson, Attorney, *representing* AARP

Rick D. Chamberlain, Attorney, *representing*, Wal-Mart Stores East LP and Sam's East, Inc.

Marc Edwards, James A. Roth, and C. Eric Davis, Attorneys, *representing* Oklahoma Hospital Association

Matthew Dunne, General Attorney, *representing* United States Department of Defense and all Other Federal Executive Agencies

FINAL ORDER

BY THE COMMISSION:

The Corporation Commission of the State of Oklahoma ("Commission") being regularly in session and the undersigned Commissioners being present and participating, there comes on for consideration and action the Report and Recommendation of the Administrative Law Judge ("ALJ") for an order of the Commission.

I. PROCEDURAL HISTORY

The procedural history of this Cause through the date of the hearing held before the ALJ is contained in the Report and Recommendations of the Administrative Law Judge filed December 11, 2017 ("ALJ Report").

On December 18, 2017, the Public Utility Division ("PUD"), Public Service Company of Oklahoma ("PSO"), the Oklahoma Attorney General ("AG"), Oklahoma Industrial Energy Consumers (OIEC"), and the Oklahoma Hospital Association ("OHA") each filed Exceptions to the ALJ Report and filed motions for oral argument.

On December 19, 2017, PSO filed a Motion for Oral Argument and Notice of Hearing.

On December 21, 2017, the Commission issued Order No. 671356, granting the Motion to Associate Counsel filed herein by PSO related to Gerardo Noel Huerta, a member of the State Bar of Texas.

On December 22, 2017, PSO filed a Response to OIEC, AG and OHA's Exceptions to the ALJ Report; OIEC filed a Response to the Exceptions of PSO; the United States Department of Defense and all other Federal Executive Agencies ("DOD/FEA") filed a Response to Exceptions to the ALJ Report; and AARP filed a Response to the Exceptions to the ALJ Report.

On January 4, 2018, the Commission granted the Motions for Oral Argument and proceeded to hear the exceptions.

II. SUMMARY OF EVIDENCE

The summary of evidence is contained in the ALJ Report.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

THE COMMISSION FINDS that it is vested with jurisdiction, pursuant to Article IX, Section 18, of the Oklahoma Constitution, 17 O.S. §§ 151 *et seq.*, and the rules of the Commission.

THE COMMISSION FURTHER FINDS that notice of these proceedings was proper and was given as required by law and the orders of the Commission.

THE COMMISSION FURTHER FINDS that in the exercise of its legislative, judicial and executive powers it is required to reach its own conclusions based upon the evidence before it and that it may adopt, reject, restrict, or expand any or all findings and recommendations of the ALJ. *State ex rel. Cartwright v. Oklahoma Natural Gas Co. and Oklahoma Corporation*

Commission, 1982 OK 11, ¶8, 640 P.2d 1341, 1343.

Based upon a full review and evaluation of the ALJ Report and the record, and having heard the arguments of counsel, the Commission hereby adopts and incorporates by reference the recommendations set forth in the ALJ Report appended hereto as Attachment 1, except as otherwise stated herein.

Motion to Strike (ALJ Report pp. 9-10, IV ¶¶ 3-4)

While the Commission generally agrees with the above-cited statements of the ALJ, the Commission clarifies that the statements should not be construed as prohibiting parties from making any reference at any time to any stipulations and settlement agreements adopted in the past by the Commission. Also, the Commission recognizes and cautions that parties who agreed to settlement provisions are expected to follow them, and that compliance with Commission orders is and will be required.

Northeastern Unit 4 (ALJ Report p. 18, ¶¶ 51-59)

THE COMMISSION FINDS, having considered the particular facts and circumstances in this Cause and emphasizing that evaluation of this type of issue must be done on a case-by-case basis, that the Commission agrees in part with the ALJ's recommendation that would authorize a return of the investment associated with Northeastern Unit 4 ("NE 4") but not a return on the remaining investment. In balancing the interests of ratepayers and shareholders, THE COMMISSION FINDS it appropriate under the circumstances presented here to authorize a return of the investment associated with NE 4 and recovery of the carrying cost on the remaining investment at the cost of debt allowed in this proceeding.

Cost of Capital: Capital Structure, Cost of Debt, Return on Equity & Rate of Return (ALJ Report pp. 20-22, ¶¶ 62-73)

The Commission agrees with the ALJ's recommendation on PSO's capital structure and cost of debt and adopts paragraphs 62 through 64 of the ALJ Report. In addition, the Commission agrees with the ALJ's analysis and recitals to the record as far as the issue of Return on Equity ("ROE") is concerned in this case, except for her ultimate conclusion. Therefore, the Commission adopts paragraphs 65 through 72, except for the last sentence of paragraph 72 where the ALJ recommends that the Commission adopt a 9.0 percent return on equity.

The Commission has reviewed all the written and oral testimony of the expert witnesses offered in this Cause, including all models utilized by each ROE witness, and has given full consideration to the oral argument presented on the issue. After such review, the Commission finds that the appropriate ROE for PSO going forward should be 9.3 percent. The Commission further finds that a 9.3 percent return on equity meets all the necessary elements set forth in the *Hope* case (*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)) as listed by the ALJ in her report in paragraph 65. A 9.3 percent ROE will give PSO the opportunity to earn a fair return on its investment, it will allow PSO a return similar to returns on other similarly risky investments, it will provide confidence in the financial integrity of the company, and will allow the company to attract capital. Finally, the 9.3 percent ROE balances the interests of both the investor and the consumer.

Based on the above, the Commission finds that PSO's overall rate of return that results from the capital structure and cost of capital determined above is 6.88% rather than the 6.73% overall rate of return set forth in paragraph 73 of the ALJ Report, as is shown below.

Description	Capital Ratio	Cost Rate	Weighted Average Cost
Long Term Debt	51.49%	4.60%	2.37%
Common Equity	48.51%	9.30%	4.51%
Total Capital	100%		6.88%

SPP Fees and Expenses (ALJ Report p. 25, ¶¶ 91 and 92)

THE COMMISSION FINDS that the recommendation of the ALJ to disallow SPP fees and expenses requested by PSO [SPP Schedule 9 NITS (Network Integration Transmission Service) in the amount of $13,994,625] as addressed by the ALJ at Paragraphs 91 and 92 of the ALJ Report should not be adopted.

In her recommendation that such expenses should not be allowed, the ALJ cited portions of testimony in which it was established the SPP fees and expenses were not effective within the test year or the six-month post-test year period. In this instance, the amount of the SPP fees and expenses at issue were known and measurable within the applicable test year plus six-months post-test year period. The establishment of the obligation of PSO to pay those fees and expenses occurred during the applicable test year plus six-months post-test year period when the SPP established its formula rates in May of 2017 which included the SPP Schedule 9 NITS charges at issue. This was one month before the end of the six-months post-test year period, which ended

June 30, 2017. The noted expense was to become effective on July 1, 2017, which was one day after the end of the six-months post-test year period. (Jason Chaplin, Resp. Test. 10:11-14 Sept 21, 2017)

The statute relied upon by various parties arguing the position expenses should not be allowed because of being outside the six-months post-test year period is 17 O.S. § 284 - *Application to Change Rates and Charges - Effect Given to Known and Measurable Changes* - which states:

> In its review and examination of an application by a utility to change its rates and charges . . . the Corporation Commission shall give effect to known and measurable changes occurring or reasonably certain to occur within six (6) months of the end of the test period upon which the rate review is based. (emphasis added)

As shown by the emphasized word "shall," this statute *requires* all known and measurable changes that occur or are reasonably certain to occur within the test year or the six-month post-test year period be given effect in establishing new rates for a public utility. However, that language does not *limit* consideration by the Commission to the time period as was asserted. The Commission has reviewed this issue in previous causes and determined it has the power to consider known and measurable adjustments past the six-months post-test year period as was detailed at pages 21 and 22 of PSO's exceptions. (*See* Order No. 492407 in Cause No. PUD 200300076 and Order No. 545168 in Cause No. PUD 200600285)

The ALJ accepted the argument that since the payment obligation was not *effective* until one day after the end of the six-months post-test year period that the expense did not *occur* within that time and therefore, is not eligible to be included in establishing rates. Despite the fact that the expense was not effective until July 1, 2017, one day after the end of the six-months post-test year period, the expense *did* occur in the six-months post-test year period because it was known and measurable and the FERC approved tariff was filed during that time period. Either way, this expense is an actual expense borne by PSO, is known and measurable, and should be allowed in the rates to be established by the order to be issued in this Cause.

Depreciation (ALJ Report pp. 28-29, ¶¶ 104-110)

The Commission does not adopt paragraph 108 of the ALJ Report with respect to net salvage, and would adopt the position of PUD witness Carolyn Weber. Further, paragraph 109 of the ALJ Report should read as follows: THE COMMISSION FURTHER FINDS that, based upon the record of this Cause the service lives recommended by the Attorney General are adopted.

Federal Tax Legislation (ALJ Report pp. 34-35, ¶¶ 134-138)

In her report, the ALJ appropriately recognized the Commission's duty and authority in setting rates. The ALJ also recognized the existence of federal tax reform efforts underway at the time of the ALJ hearing. As set forth in her report, this issue was raised after questions by Commissioner Anthony to OIEC witness Mark Garrett and PSO witness Randy Hamlett. Accordingly and consistent with the ALJ's recommendation insofar as it recommends some action be taken, the Commission takes judicial notice of the Tax Cuts and Jobs Act, P.L. 115-97, enacted December 22, 2017, by the federal government reducing the federal corporate income tax rate to 21 percent of taxable income beginning January 1, 2018. Further, the Commission takes judicial notice of Commission Order No. 671981 in which the Commission on January 9, 2018, ordered PSO, in part, to:

> [R]ecord a deferred liability beginning on [January 9, 2018,] to reflect the reduced federal corporate tax rate to 21 percent and the associated savings in excess ADIT and any other tax implications of the Act on an interim basis subject to refund until utility rates are adjusted to reflect the federal tax savings through … a final order in pending rate case PUD 201700151…[and that] the amounts of any refunds determined to be owed to customers shall accrue interest at a rate equivalent to PSO's cost of capital as recognized in Order No. 658529 issued in Cause No. PUD 201500208 until issuance of a final order in PSO's pending rate case in Cause No. PUD 201700151… .

Order No. 671981, p. 4.

THE COMMISSION FINDS that PSO shall immediately reduce its rates in the amount necessary to reflect the lower federal corporate tax rate of 21 percent, distributed across rate classes in proportion to their share of the revenue requirement approved in this proceeding. THE COMMISSION FURTHER FINDS that all other tax savings resulting from P.L. 115-97, including the savings from the time period of January 9, 2018, through the date of this Order, and including savings through amortization of "excess" accumulated deferred taxes ("ADIT"), shall continue to be recorded as a deferred liability subject to refund with interest at the cost of capital pursuant to the provisions of Order No. 671981. The mechanism for flowing refunds back to customers for these tax savings and the consideration of all tax impacts of P.L. 115-97 shall be addressed as set forth in Order 671981 through PSO's next base rate case, or in a separately-filed proceeding, or through a final order in Cause No. PUD 201700572.

ORDER

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION OF OKLAHOMA that the ALJ Report appended hereto as Attachment 1, subject to and as amended or superseded by the modifications detailed hereinabove, is hereby adopted and incorporated herein as if fully set forth, as the order of the Commission.

IT IS FURTHER ORDERED that PSO shall, within three (3) business days of entry of this Order, file an accounting exhibit reflecting the terms of this Order.

IT IS FURTHER ORDERED that PSO shall, within thirty (30) days after the date of this Order, submit to the Director of the Public Utility Division tariffs consistent with the findings set forth herein, and that the rates, charges, and tariffs shall be effective with the first regular billing cycle after such tariffs are approved by the Director of the Public Utility Division.

OKLAHOMA CORPORATION COMMISSION

Dana L. Murphy
DANA L. MURPHY, Chairman

J. Todd Hiett
J. TODD HIETT, Vice Chairman

Bob Anthony
BOB ANTHONY, Commissioner

DONE AND PERFORMED this 31 day of January 2018.

BY ORDER OF THE COMMISSION:

Peggy Mitchell
PEGGY MITCHELL, Secretary

ATTACHMENT 1

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES AND THE ELECTRIC SERVICE RULES, REGULATIONS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. 201700151

HEARING: October 30-31, November 1-3, and 6-9, 2017, in Courtroom 301
2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105
Before Mary Candler, Administrative Law Judge

APPEARANCES: Jack P. Fite, Joann S. Worthington, and Kendall W. Parrish, Attorneys *representing* Public Service Company of Oklahoma
Dara M. Derryberry, Deputy Attorney General, and Katy Evans Boren, Jared B. Haines and A. Chase Snodgrass, Assistant Attorneys General *representing* Office of Attorney General, State of Oklahoma
Judith L. Johnson and Natasha M. Scott, Deputy General Counsels, and Michael L. Velez, Lauren Hensley and Olivia Waldkoetter, Assistant General Counsels *representing* Public Utility Division, Oklahoma Corporation Commission
Thomas P. Schroedter, Attorney *representing* Oklahoma Industrial Energy Consumers
Deborah R. Thompson, Attorney *representing* AARP
Rick D. Chamberlain, Attorney *representing* Wal-Mart Stores East, LP and Sam's East, Inc.
Marc Edwards, James A. Roth, and C. Eric Davis, Attorneys *representing* Oklahoma Hospital Association
Matthew Dunne, Attorney *representing* United States Department of Defense and all other Federal Executive Agencies

<u>REPORT AND RECOMMENDATION OF THE ADMINISTRATIVE LAW JUDGE</u>

TABLE OF CONTENTS

This Cause comes before the Corporation Commission ("Commission") of the State of Oklahoma on the Application of Public Service Company of Oklahoma ("PSO" or "Company") seeking an adjustment to its rates and charges and the electric rules, regulations and conditions of electric service for electric service for the State of Oklahoma.

I. SUMMARY OF RECOMMENDATION

The Administrative Law Judge ("ALJ") respectfully submits this report and recommendation. In summary, PSO has requested a base rate revenue increase of $169,667,526. The ALJ recommends a base rate revenue increase of $81,220,570. Attachment "A" to this report is an accounting exhibit that reflects the ALJ's recommendation. The ALJ recommends the Company's proposed capital structure of 51.5 percent debt and 48.5 percent equity and a 4.6 percent cost of long term debt. The ALJ recommends 9.00 percent return on equity.

The ALJ recommends allowing recovery of Northeastern Unit 4 but not recovery on Northeastern Unit 4 since it is not being used to supply power to customers at this time. The ALJ recommends moving the System Reliability Rider and the Advanced Meter Infrastructure Rider from riders to base rates. The ALJ recommends that 50 percent of the annual incentive plan be excluded from rates while 100 percent of the long-term incentive plan be excluded from rates. The ALJ recommends that the Supplemental Executive Retirement Plan be 100 percent excluded from rates. Other recommendations are delineated within this document.

The ALJ recommends PSO's revenue distribution proposal that follows the revenue distribution recommendation from the final order in PSO's last rate case.

II. JURISDICTION AND NOTICE

PSO is an Oklahoma corporation authorized to do business in the State of Oklahoma. PSO is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity at wholesale and retail levels within the State of Oklahoma. The Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma, 17 O.S. §§ 151 et seq., and the Rules and Regulations of this Commission. Notice is proper in this Cause and complies with Order No. 667373 and the requirements of OAC 165:5-7-51.

III. PROCEDURAL HISTORY

1. On May 12, 2017, PSO filed its Notice of Intent, giving notice to the Commission of PSO's intent to file an Application seeking to modify the rates and charges for PSO's Oklahoma jurisdiction customers as well as amend PSO's Electric Service Rules, Regulations and Conditions of Service.

2. On May 16, 2017, the ALJ filed a Notice of Hearing for the Pre-Hearing Conference to be held on June 7, 2017.

3. On May 18, 2017, the Office of the Attorney General ("Attorney General") filed an Entry of Appearance for Dara M. Derryberry, Katy Evans Boren and Jared B. Haines.

4. On May 19, 2017, Thomas P. Schroedter filed an entry of appearance on behalf of Oklahoma Industrial Energy Consumers ("OIEC").

5. On June 7, 2017, the Pre-Hearing Conference was continued by agreement of the parties to June 15, 2017.

6. On June 15, 2017, the Pre-Hearing Conference was held and a Procedural Schedule for the processing of this Cause was recommended.

7. On June 20, 2017, Deborah R. Thompson filed an Entry of Appearance on behalf of AARP.

8. On June 30, 2017, PSO filed the Application, the Application Package (Schedules) Volume 1 and the Direct Testimony of: John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Donald R. Dohrmann, Steven L. Fate, Brian J. Frantz, Randall W. Hamlett, Jennifer L. Jackson, Derek S. Lewellen, Thomas J. Meehan, Scott A. Ritz, C. Richard Ross, Tommy J. Slater, Wayman L. Smith, John J. Spanos, Michael J. Vilbert and David J. Wathen.

9. On July 7, 2017, a Notice of Hearing was filed setting a Pre-Hearing Conference for July 14, 2017.

10. On July 11, 2017, Rick D. Chamberlain filed an entry of appearance on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

11. On July 14, 2017, the ALJ's Preliminary Order was recommended.

12. On July 19, 2017, the Public Utility Division ("PUD") filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements.

13. On July 20, 2017, PSO filed Summaries of Direct Testimony of: John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Donald R. Dohrmann, Steven L. Fate, Brian J. Frantz, Randall W. Hamlett, Jennifer L. Jackson, Derek S. Lewellen, Thomas J. Meehan, Scott A. Ritz, C. Richard Ross, Tommy J. Slater, Wayman L. Smith, John J. Spanos, Michael J. Vilbert and David J. Wathen.

14. On July 26, 2017, PSO filed an Errata to Work Paper G-06.

15. On August 24, 2017, the Commission issued Order No. 667373 Preliminary Order establishing the procedural schedule and notice requirements for the processing of this Cause.

16. On August 25, 2017, Matthew Dunne filed an Entry of Appearance on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA"). Also, on this date, DoD/FEA filed a Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys along with a Notice of Hearing setting the Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For

Waiver of Certain Requirements Pertaining to Out-of-State Attorneys for hearing on August 31, 2017. A Proposed Order Admitting to Practice and Waiving Certain Requirements Pertaining to Out-of-State Attorneys was also filed.

17. On August 29, 2017, PSO filed an Errata to Schedule K-1; Schedule K-2A; Schedule K-2B; WPL-1; WPL-1-1; WPL-1-2; WPL-2; WPL-3; WPL-4; WPL-5; WPL-6; WPL-8; WPL-11

18. On August 31, 2017, the Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys was heard and recommended.

19. On September 1, 2017, the Oklahoma Hospital Association ("OHA") filed an entry of appearance for Marc Edwards, James A. Roth and C. Eric Davis.

20. On September 14, 2017, PSO filed its Response to OIEC's Third Set of Data Requests.

21. On September 21, 2017, the following testimonies and exhibits were filed:

a. Responsive Testimony was filed by James B. Alexander, Todd F. Bohrmann, Edwin C. Farrar, Marlon F. Griffing, Ph.D. and William W. Dunkel on behalf of the Attorney General;

b. Responsive Testimony for David J. Garrett (Part I Risk and Return and Part II Depreciation) and Mark E. Garrett on behalf of OIEC. Also, Testimony and Exhibits of David C. Parcell were filed on behalf of OIEC and Wal-Mart;

c. Responsive Testimony for McKlein Aguirre, Kathy Champion, Jason C. Chaplin, Jeffrey Dunsworth, David Melvin, James E. Mitschke II, Kiran Patel, Geoffrey M. Rush, Jeremy K. Schwartz, Amy Taylor, Elbert D. Thomas, John Walkup, and Carolyn Jean Weber were filed on behalf of PUD. PUD also filed its Accounting Exhibit; and

d. Responsive Testimony for Maureen L. Reno was filed on behalf of DoD/FEA. Matthew Dunne filed a Certificate of Compliance on this date.

22. On September 22, 2017, Mark E. Garrett filed an Errata to his Responsive Testimony.

23. On September 25, 2017, the following Summaries of Responsive Testimony were filed: David C. Parcell and David J. Garrett on behalf of OIEC and Wal-Mart; Mark E. Garrett on behalf of OIEC; McKlein Aguirre, Kathy Champion, Jason C. Chaplin, Jeffrey Dunsworth, David Melvin, James E. Mitschke II, Kiran Patel, Geoffrey M. Rush, Jeremy K. Schwartz, Amy Taylor, Elbert D. Thomas, John Walkup, Carolyn Jean Weber on behalf of PUD; James B. Alexander, Todd F. Bohrmann, William W. Dunkel, Edwin C. Farrar, and Marlon F. Griffing, Ph.D., on behalf of the Attorney General; and Maureen L. Reno on behalf of DoD/FEA.

24. On September 26, 2017, David J. Garrett filed an Errata to his Responsive Testimony, Part II.

25. On September 27, 2017, William W. Dunkel filed an Errata to his Responsive Testimony. Marlon F. Griffing, Ph.D. also filed an Errata to his Responsive Testimony on this date.

26. Also on September 27, 2017, A. Chase Snodgrass filed an Entry of Appearance on behalf of the Attorney General.

27. On September 28, 2017, Kendall W. Parrish filed an Entry of Appearance on behalf of PSO.

28. On October 2, 2017, Marlon F. Griffing, Ph.D. filed a Second Errata to his Responsive Testimony.

29. On October 3, 2017, the following documents were filed:

a. Motion to Associate Counsel on behalf of PSO was filed along with a Notice of Hearing setting the Motion to Associate Counsel for hearing on October 5, 2017;

b. Jeremy K. Schwartz filed Responsive Testimony regarding Cost of Service and Rate Design on behalf of PUD as did Steve W. Chriss on behalf of Wal-Mart; and Larry Blank on behalf of DoD/FEA; and

c. Responsive Testimony of Scott Norwood and Mark E. Garrett on behalf of OIEC were filed. Also, Rate Design Testimony of James B. Alexander, Todd F. Bohrmann and Edwin C. Farrar on behalf of the Attorney General; Responsive Testimony of Maureen L. Reno, Responsive Testimony of Maureen L. Reno Redline version and Errata to the Responsive Testimony of Maureen L. Reno on behalf of DoD/FEA.

30. On October 5, 2017, two Supplemental Testimonies and the Summary of Supplemental Testimony of Maureen L. Reno on behalf of DoD/FEA were filed. Also on this date, Summaries of Testimony were filled by Larry Blank on behalf o DoD/FEA, Steve W. Chriss on behalf of Wal-Mart; Scott Norwood and Mark E. Garrett on behalf of OIEC; Todd F. Bohrmann, James B. Alexander and Edwin C. Farrar on behalf of the Attorney General.

31. Also on October 5, 2017, the Motion to Associate Counsel was heard and recommended.

32. On October 10, 2017, Statements of Position were filed by AARP and OHA.

33. On October 11, 2017, Rebuttal Testimony of James O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Steven L. Fate, Randall W. Hamlett, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert, David J. Wathen were filed on behalf of PSO.

34. On October 12, 2017, the Commission issued Order No. 668994, Order Granting Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys. Also, Proof of Publication and Customer Notice was filed by PSO.

35. On October 13, 2017, Summaries of Rebuttal Testimony were filed by John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew C. Carlin, Steven L. Fate, Randall W. Hamlett, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert and David J. Wathen on behalf of PSO.

36. On October 16, 2017, Rebuttal Testimony regarding Cost of Service/Rate Design was filed by Steven L. Fate, Jennifer L. Jackson, Rebuttal Testimony of John O. Aaron and A. Naim Hakimi on behalf of PSO; Rebuttal Testimony by Jason C. Chaplin and Geoffrey M. Rush on behalf of PUD.

37. On October 18, 2017, Summaries of Rebuttal Testimony were filed by: Jason C. Chaplin and Geoffrey M. Rush on behalf of PUD and Summaries of Cost of Service/Rate Design Testimony of John O. Aaron, Steven L. Fate, A. Naim Hakimi and Jennifer L. Jackson on behalf of PSO.

38. On October 20, 2017, Maureen L. Reno on behalf of DoD/FEA filed clean and redline versions of her September 21, 2017, Responsive Testimony; clean and redline versions of her Supplemental Testimony filed on October 3, 2017; Errata to Supplemental Testimony and Second Errata to Responsive Testimony. Also on this date, OIEC filed a Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony.

39. On October 23, 2017, a Notice of Hearing on the Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony was filed setting the Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony for hearing on October 26, 2017.

40. On October 24, 2017, Oral Surrebuttal Issues were filed by DoD/FEA, the Attorney General, PUD, Wal-Mart and OIEC. Also on this date, Exhibit Lists for PUD and Wal-Mart were filed.

41. On October 25, 2017, Exhibit Lists for OIEC, PSO, Attorney General, OHA and AARP were filed.

42. On October 26, 2017, the following documents were filed or hearings took place:

a. an Amended Rebuttal Testimony of Randall W. Hamlett on behalf of PSO was filed;

b. the Motion to Strike Portions of Randall W. Hamlett's Testimony was heard and recommended with instruction;

c. Affidavits of John O. Aaron, Pauline M. Ahern, Andrew R. Carlin, Steven L. Fate, A. Naim Hakimi, Randall W. Hamlett, Jennifer L. Jackson, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert, and David J. Wathen were filed;

d. the Pre-Hearing Conference was held; and

e. Public Comments were also heard and the sign-in sheet was filed.

43. On October 27, 2017, Public Comments were filed.

44. On October 30, 2017, Exhibits No. 1-9 were filed. The Hearing on the Merits was heard and continued each day through November 9, 2017, at which time the ALJ took the matter under advisement.

45. On November 1, 2017, an Updated Exhibit MLR-1S ROE Comparison was filed as was Exhibit 10.

46. On November 2, 2017, a Public Comment Sign In Sheet was filed. Also, Exhibits No. 11-23 were filed.

47. On November 3, 2017, the following documents were filed:

a. Public Comment was filed;

b. Exhibits No. 24-58 were filed (excluding Exhibit No. 51);

c. An Affidavit of Steven F. Baker was filed;

d. PSO filed AEP-PSO Electric Utility Rate Increase 1 of 2 and 2 of 2; and

e. Exhibit 39 and Exhibit 51 were filed.

48. On November 6, 2017, Exhibits 59 and 60 were filed.

49. On November 7, 2017, Public Comment File EEI Briefing Book was filed. Exhibit 61 was also filed on this date.

50. On November 8, 2017, Public Sign-In Sheet was filed as well as Exhibits 62, 63 and 64.

51. On November 9, 2017, the Affidavit of Steve W. Chriss was filed, as was Exhibit 46A.

52. On November 13, 2017, Public Comment was filed.

53. On November 15, 2017, Public Comments were filed.

54. On November 20, 2017, the All Parties Issue Lists was filed.

55. Also on November 20, 2017, PSO filed the Supplemental Testimony Summary of Randall W. Hamlett. The Proposed Findings of Fact and Conclusions of Law were filed by PSO, OIEC, AARP, Attorney General, Wal-Mart, DoD/FEA, and PUD on this date.

56. On December 4, 2017, the Affidavit of Larry Blank was filed.

IV. MOTION TO STRIKE

On October 20, 2017, OIEC filed a Motion to Strike Portions of Randall W. Hamlet's Rebuttal Testimony ("Motion"). The Motion was heard at the Pre-Hearing Conference on October 26, 2017. OIEC's Motion requested the striking of portions of Mr. Hamlett's Rebuttal Testimony that cited a settlement agreement as precedential. OIEC argued that a settlement agreement in a prior case was cited as precedential and binding, notwithstanding the Settlement Agreement, which was signed by PSO and the other parties to the Agreement, expressly provided that nothing in the Agreement "shall constitute [] or be cited as precedent." Settlement Agreement, § 8(e), filed on June 17, 2014, in Cause No. PUD 201300217. According to the cited Settlement Agreement, the parties to the Settlement further agreed that the Commission's decision to enter an order consistent with the Settlement Agreement was binding only "as to the matters decided regarding the issues described in the [Settlement Agreement], but the decision [was] not to be binding with respect to similar issues that might arise in other proceedings." *Id.*

The Attorney General, AARP, Wal-Mart, and OHA supported OIEC's Motion to Strike and noted that this was a recurring issue. (Oct. 26, 2017, Excerpt Transcript of Pretrial Conference at KA7-10). At the hearing on the Motion, PSO agreed that the Motion to Strike should be granted. The ALJ recommended granting the motion with instruction. The ALJ directed PSO to file amended testimony that removed testimony that cited settlement agreement(s) as precedential. The ALJ also informed the parties that the issue would be addressed further in the ALJ report because it is an issue that re-occurs and should be addressed. (*Id.*, p. KA13). PSO filed Amended Testimony of Hamlett as directed.

Reliance on settlement agreements that have been approved by the Commission in which the parties to the agreement have agreed do not constitute precedent in other cases and that should not be cited as precedent in other cases will cause a chilling effect, deterring settlements in future proceedings. Therefore, it is the recommendation of the ALJ that the Commission finds and declares that parties shall not rely upon, and shall not file or elicit testimony that relies upon, provisions of settlement agreements that provide that they are not binding in other proceedings and are not to be cited as precedent, or that contain similar language, except where necessary to enforce the terms of the settlement agreement or to determine rights arising under the settlement agreement.

This issue came up several times throughout the Hearing on the Merits and involved not just one witness's testimony. A simple statement of recommendation of this Motion does not adequately address this issue in this Cause. Therefore, the ALJ is recommending broader language related to this issue in the below recommended Findings of Fact and Conclusions of Law.

V. SUMMARY OF THE EVIDENCE

Documents filed in this Cause are contained in the record kept by the Court Clerk of the Commission. Pre-filed testimony was filed of record and live testimony was offered at the Hearing on the Merits.. The entirety of the live testimony offered is contained in the transcripts of these proceedings. Summary of the testimony is set forth in Attachment "B" attached hereto and incorporated herein.

Exhibits:

Exhibits were admitted into evidence at the Hearings on the Merits and are filed of record in this Cause. The list of those Exhibits is set forth in Attachment "C" attached hereto and incorporated herein.

VI. FINDINGS OF FACT AND CONCLUSIONS OF LAW

After consideration of all evidence in this Cause, the ALJ recommends the Commission adopt the following Findings of Fact and Conclusions of Law. Such findings and conclusions are numbered sequentially for clarity. The ALJ's findings being with "The Commission" finds. There is no presumption on the part of the ALJ that she speaks for the Commission. The ALJ has used a format that she hopes can be easily used by the Commissioners, should there be a desire to use any of these Findings of Fact and Conclusions of Law, in a final order. Any subheadings used are also for clarity.

<u>Jurisdiction and Notice</u>

1. THE COMMISSION FINDS that PSO is an Oklahoma corporation authorized to do business in the State of Oklahoma. PSO is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity at wholesale and retail levels within the State of Oklahoma. The Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma, 17 O.S. §§ 151 *et seq.*, and the Rules and Regulations of this Commission.

2. THE COMMISSION FURTHER FINDS that notice is proper in this Cause and complies with Order No. 667373 and the requirements of OAC 165:5-7-51.

<u>OIEC Motion</u>

3. THE COMMISSION FURTHER FINDS that, regarding the OIEC Motion, the Commission does not rely upon testimony that inappropriately relies upon previous settlement agreements as precedential.

4. THE COMMISSION FURTHER FINDS that parties shall not rely upon, and shall not file or elicit testimony that relies upon, provisions of settlement agreements that explicitly provide that they are not binding in other proceedings and are not to be cited as precedent, or that contain similar language, except where necessary to enforce the terms of the settlement agreement or to determine rights arising under the settlement agreement.

Test Year

5. THE COMMISSION FURTHER FINDS that a review of a utility company's rates relies on an investigation of the test year, a "mirror view of the past suspended within a limited but definite time frame through which we prophesy its duplication in the future." *Sw. Pub. Serv. Co. v. State*, 1981 OK 136, ¶ 14, 637 P.2d 92, 98. PSO is entitled to the opportunity to earn a fair rate of return on its property invested and in use during the test year, *see id.*; *Lone Star Gas Co., a div. of Enserch Corp v. State*, 1986 OK 53, ¶ 4, 745 P.2d 723, 725, after making known and measurable adjustments for changes occurring within six months after the test year, 17 O.S. § 284. PSO is also entitled to include reasonable operating expenses necessary to provide service with its investments. *Turpen v. Okla. Corp. Comm'n*, 1988 OK 126, ¶ 10 n.7, 769 P.2d 1309, 1316 n.7.

6. THE COMMISSION FURTHER FINDS that the test year in this Cause is the twelve-month period ended December 31, 2016. The Commission's Minimum Standard Filing Requirements, specifically OAC 165:70-1-2, define "test year" as the "twelve (12) month period used in determining rate base, operating income and rate of return." Title 17, § 284 of the Oklahoma Statutes provides for consideration of changes beyond the test year as follows:

> In its review and examination of an application by a utility to change its rates and charges pursuant to Sections 137, 152 or 158.27 of Title 17 of the Oklahoma Statutes, and in any order resulting therefrom, the Corporation Commission shall give effect to known and measurable changes occurring or reasonably certain to occur within six (6) months of the end of the test period upon which the rate review is based.

7. THE COMMISSION FURTHER FINDS that Commission Order No.657877 as modified by Order No. 658529 in Cause No. PUD 201500208 set rates as determined by the last PSO rate case. Testimony was offered by multiple witnesses that stated the new rates approved in Cause No. PUD 201500208 were effective beginning January 2017, outside of the test year for this Cause.

8. THE COMMISSION FURTHER FINDS that the test year in this Cause is the twelve-month period ended December 31, 2016, and that pursuant to 17 O.S. § 284, the six-month post test year period ended on June 30, 2017.

Legal Standard

9. THE COMMISSION FURTHER FINDS that PSO bears the burden of proof with regard to whether its investments are in service and as to the reasonable level of expenses necessary to provide service. Indeed, the "burden of proof with respect to every element of value entering into the rate base is upon the public utility." *Mullendore Gas Co. v. City of Stillwater*, 1926 OK 325, ¶ N, 250 P. 895, 898-99 (citing *Okla. Nat. Gas. Co. v. Corp. Comm'n of Okla.*, 1923 OK 400, 216 P. 917.) The "burden of proof rests on [the utility company], not the Corporation Commission." *Lone Star Gas Co., a Div. of Enserch Corp. v. Corp. Comm'n of State of Okla.*, 1982 OK 79, ¶ 4, 648 P.2d 36, 42.

Plant in Service

10. THE COMMISSION FURTHER FINDS that PSO's plant balances are clearly known and measurable at the end of the six-month post-test year period. All projects actually completed and in service within six-months of test year-end should be included in rate base. The Commission finds that the utility plant in service balance as of June 30, 2017, should be adopted as the utility plant in service balance to be included in the rate base in this Cause.

11. THE COMMISSION FURTHER FINDS that the gross amount of plant in service at the June 30, 2017, six-month post-test year-end of $5,052,446,776 is set forth in the filed Issues Spreadsheet ($4,983,250,551 + $69,196,225). This includes both Plant in Service recorded in FERC Account 101 and Completed Construction Not Classified recorded in FERC Account 106. No party opposed the prudence of any of the capital additions made since the last rate case through the six-month post-test year period of June 30, 2017.

12. THE COMMISSION FURTHER FINDS that Construction Work in Progress ("CWIP") not in service as of June 30, 2017, is not included in rate base. Since the Commission has adopted the Plant in Service balance as of June 30, 2017, the Commission finds that no CWIP should be included in the rate base of PSO. No adjustment is necessary to reflect this decision, since the booked plant in service as of June 30, 2017, captures all CWIP requested for those plants that were actually placed in service as of June 30, 2017.

Accumulated Depreciation

13. THE COMMISSION FURTHER FINDS that all parties recommended an increase to Accumulated Depreciation to update for the six-month post-test year level. Mr. Farrar and Mr. Garrett recommend the balance provided by the Company while Ms. Weber recommends a lower amount and includes an adjustment to move the Northeastern Unit 4 balance to a regulatory asset. (Weber Rev. Req. Resp. Test. at 45:7-48: table, Farrar Rev. Req. Resp. Test. at 6:19, M. Garrett Rev. Req. Resp. Test. at 8: Table 1:2, Hamlett Reb. Test. at 23:10 -15.) The recommendations of Mr. Garrett and Mr. Farrar matched the data request responses provided to the parties by PSO. Mr. Hamlett agreed with Mr. Farrar's and Mr. Garrett's adjustment of $32,673,645. (Hamlett Rebuttal, p. 23, lines 8-13.)

14. THE COMMISSION FURTHER FINDS that the balance of accumulated depreciation be increased by $32,673,645 in order to give effect to the known and measurable increase in the deferred taxes that occurred within six months of the test year end.

Prepaid Pension

15. THE COMMISSION FURTHER FINDS that PSO included $92,361,841 in prepaid pension assets, the 13-month average balance at December 31, 2016, in rate base. Applying PSO's overall grossed-up[1] return results in an annual revenue requirement of approximately $6.4 million. When compared to the pension cost savings of $11.9 million

[1] The grossed-up return includes an amount for the taxes that the Company will have to pay on the amount such that, after-tax, the Company will earn its requested weighted average cost of capital.

generated by the additional pension contributions, the benefit to PSO's customers is approximately $4.7 million. (Hamlett Direct, p. 31, lines 13-20.) The prepaid pension asset produces benefits for PSO's customers.

16. THE COMMISSION FURTHER FINDS that the prepaid pension assets are decreased by $344,729 to account for the six-month post-test year values. (Patel Direct, p. 5, line 9.)

17. THE COMMISSION FURTHER FINDS that OIEC and the Attorney General recommended the removal of the 2003 beginning balance associated with the pension prepayment. (Farrar Responsive, p. 8, lines 2-3 and Garrett Responsive, p. 9, lines 14-16.)

18. THE COMMISSION FURTHER FINDS that the 2003 pension prepayment balance was approved by the Commission and included in rate base in previous rate cases including Cause No. PUD 201500208 and this balance will continue to be allowed in rate base consistent with previous Commission treatment. (Hamlett Rebuttal, p. 18, lines 5-10.)

Materials and Supplies and Fuel Inventory

19. THE COMMISSION FURTHER FINDS that PSO has included in its rate base the 13-month average balance of materials and supplies and fuel inventories through December 31, 2016, in the amount of $62,391,612 (Schedule B-2) as required by OAC 165:70-5-22(4). The Attorney General and OIEC adjusted the materials and supplies inventory by a reduction of $5,886,208. PSO did not contest this adjustment. (Hamlett Rebuttal, p. 26, lines 1-3 and Issues Spreadsheet.)

20. THE COMMISSION FURTHER FINDS that materials and supplies inventory shall be reduced by $5,886,208.

21. THE COMMISSION FURTHER FINDS that PSO made an adjustment to PSO's fuel inventory in working capital by decreasing a 13-month average Coal Inventory provided on WPB-05, p. 1 of 3, by $10,061,281 for the test year-end value by $11,016,346 to incorporate the optimal target level of tons required at PSO's coal-fired plants (Northeastern Unit 3 and Oklaunion) necessary to provide reliable service to its customers. (Hamlett Direct, p. 37, lines 3-7.) Ms. Patel and Mr. Farrar recommend an increase of $289,914. PSO did not contest the adjustment. (Hamlett Rebuttal, p. 26, lines 4-7.) The Commission adopts the adjustment proposed by PUD witness Patel and Attorney General witness Farrar.

Off-system Trading Deposits

22. THE COMMISSION FURTHER FINDS that PSO reduced rate base by $63,582 for Off-System Trading Deposits which represents the net amount of funds deposited by and with PSO for its off-system purchase and sales activities on its books at the test year-end. During the test year, PSO had less funds on deposit with counter parties than it required from counter parties resulting in the test year rate base reduction. These funds are required both by PSO and of PSO as security for purchase and sales activities.

23. THE COMMISSION FURTHER FINDS that an adjustment be made to increase the thirteen-month average balance of off-system trading deposits by $84,403 to reflect the balance as of June 30, 2017. (Patel Rev. Req. Resp. Test. at 10:5-9.)

Independent Power Producer ("IPP") System Upgrades

24. THE COMMISSION FURTHER FINDS that rate base shall be reduced by the IPP transmission credits of $1,050,066, which represent funds deposited with PSO by IPPs to off-set the transmission system upgrades necessary to interconnect the IPPs with PSO's transmission system. Since these funds were supplied by the IPPs, as required by FERC Order 2003, and not supplied by PSO investors, they are a reduction to PSO's rate base. However, PSO proposed this amount in its Application; therefore, no adjustment is required.

Accumulated Deferred Income Taxes

25. THE COMMISSION FURTHER FINDS that accumulated deferred income taxes should be updated to recognize the six-month post-test year balance. (Walkup Resp. Test. 16:18-19; Garrett Rev. Req. Resp. Test. at 8: Table 1:3; Farrar Rev. Req. Resp. Test. at 11:20-12:8.) This adjustment gives effect to the known and measurable increase in the deferred taxes that occurred within six months of test year-end. When additions to the investment levels in Plant are recognized through the 6-month period, off-setting increases in Accumulated Depreciation and Accumulated Deferred Income Tax must also be recognized. This adjustment will increase Accumulated Deferred Income Tax, resulting in a decrease to rate base of ($39,357,904). (Walkup Responsive Testimony, filed September 21, 2017, pages 16-17.)

26. THE COMMISSION FURTHER FINDS that the following reductions to rate base be adopted: $4,937,384 for excess deferred income taxes (Schedule B-2) as required by OAC 165:70-5-22(4), $15,971 for deferred investment credits (pre-1971) (Schedule B-2) as required by OAC 165:70-5-22(4) and $31,211,048 of deferred state investment tax credits (Schedule B-3, Line 29) as required by OAC 165:70-5-22(4). (It is noted that no party objected to these reductions recommended by PSO.)

Red Rock Regulatory Asset

27. THE COMMISSION FURTHER FINDS that in Commission Order No. 554328, issued in Cause No. PUD 200700465, PSO was permitted to defer as a regulatory asset a total of $10,508,157 for costs associated with the Red Rock Generation Station. The Commission further ordered that as of March 1, 2008, PSO could begin accruing a carrying cost equal to PSO's Allowance for Funds Used During Construction ("AFUDC") rate until the regulatory asset is recovered in base rates. (Order No. 554328, issued May 21, 2008, in Cause No. PUD 200700465, pp. 3-4,)

28. THE COMMISSION FURTHER FINDS that the Red Rock regulatory asset, with the balance reflected as of June 30, 2017, be included in rate base, consistent with Commission Order No. 554358.

Medicare Part D Regulatory Asset

29. THE COMMISSION FURTHER FINDS that the Medicare Part D subsidy regulatory asset of $3,919,320 (Hamlett Direct, page 33), will continue as approved in Cause No. PUD 201300217. The Commission previously approved deferral of these costs as a regulatory asset along with ongoing amortization. (Hamlett Direct, p. 34, line 19 through p. 35, line 17.)

Contributions in Aid of Construction

30. THE COMMISSION FURTHER FINDS that PSO reduced rate base for $378,434 of refundable Contribution in Aid of Construction. (Hamlett page 33 and page 36, lines 19–23.) Mr. Farrar recommended that regulatory liabilities, including Contributions in Aid of Construction, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Test. 7:6.) PUD also recommended this update and PSO agreed with PUD.

31. THE COMMISSION FURTHER FINDS and adopts PUD's recommendation to increase the Refundable Contribution in Aid of Construction adjustment in the amount of $69,740 which reduces the rate base by $69,740.

Deferred Storm Expense

32. THE COMMISSION FURTHER FINDS that the balance of previously deferred storm costs being recovered from customers would be $3,854,154 as of June 30, 2017. (Hamlett Direct, page 33 and page 34, lines 15–18.) Mr. Hamlett also testified there were six storms for which each storm's restoration efforts exceeded $1 million. The total of these six storms was $29,000,397. (Hamlett Direct, page 36, lines 8 through 11.) No party objected to the inclusion of the past storm regulatory asset deferrals in rate base. PSO has included the appropriate amount of storm regulatory asset deferrals in rate base.

33. THE COMMISSION FURTHER FINDS that amortization of storm costs will occur over four years consistent with Order No. 639314 issued in Cause No. PUD 201300217 (Hamlett Direct page 6, line 20 through page 7, line 8.)

34. THE COMMISSION FURTHER FINDS that the Attorney General recommended that regulatory assets, including the deferred storm expense, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The deferred storm expense regulatory asset requested by PSO is increased by $4,625,004 to the June 30, 2017, balance of $8,479,158.

Deferred Environmental Asset

35. THE COMMISSION FURTHER FINDS that Order No. 657877, issued in Cause No. PUD 201500208, addressed certain plant investment attributable to PSO's environmental compliance plan not in service as of July 31, 2015.

36. THE COMMISSION FURTHER FINDS that the time period for the environmental compliance plan deferral recoveries would be the date new rates are implemented in 2018 through 2040.

37. THE COMMISSION FURTHER FINDS that PUD witness Ms. Weber directly addressed the environmental deferral regulatory asset while Attorney General witness Mr. Farrar and OIEC witness Mr. Mark Garrett indirectly addressed it through their six-month post-test year updates. All of those witnesses either directly or indirectly recommended the value of the environmental deferral regulatory asset be set at the six-month post-test year level (June 30, 2017) amount.

38. THE COMMISSION FURTHER FINDS that adjustments recommended by PUD are adopted as set forth below:

a. The Commission find and adopt PUD's recommendation to increase rate base in the amount of $13,082,073 to record the balance in the Deferred Environmental Accounting Regulatory Asset account as of 12/31/16 which was omitted from PSO's pro forma adjustment listed on Schedule B.

b. The Commission find and adopt PUD's recommendation to remove PSO's pro forma adjustment for amortization of the Deferred Environmental Accounting Regulatory Asset for January 1, 2018, through June 30, 2018, which is a rate base increase of $968,689.

c. The Commission find and adopt PUD's recommendation to correct PSO's pro forma Deferred Environmental Accounting Regulatory Asset balance for corrections to calculations of depreciation, ad valorem taxes, tax depreciation and associated accumulated deferred income taxes, cost of capital grossed-up for income taxes, and omitted Comanche Generation Plant investments. The recommendation increases rate base by $531,524.

d. The Commission find and adopt PUD's recommendation to remove the monthly carrying charges on the Deferred Environmental Accounting Regulatory Asset for periods prior to June 30, 2017, which were before the regulatory asset is properly included in rate base. The PUD recommendation reduces rate base by $1,139,884.

e. The Commission find and adopt PUD's recommendation to reduce the Deferred Environmental Accounting Regulatory Asset included in PSO's pro forma rate base by $12,738,287 for the amounts included from July 1, 2017, through December 31, 2017, which are not known and measurable as the investments for those periods on which the balances were calculated were estimated to have no changes after 6/30/17.

f. The Commission find and adopt PUD's recommendation to decrease the revenue requirement by $1,380,888, the amount by which PSO's pro forma depreciation exceeded the depreciation of the Oklaunion AROs for the Ash Ponds after correcting the service life from 2020 to the estimated retirement date of the Oklaunion Plant of 12/31/2046.

<u>Deferred Pole Attachment Revenue</u>

39. THE COMMISSION FURTHER FINDS that rate base is reduced by $799,015 for deferred pole attachment revenue. (Hamlett page 33 and page 37, lines 1 – 4). No party objected to this rate base reduction.

40. THE COMMISSION FURTHER FINDS that the Attorney General recommends that regulatory liabilities, including the deferred pole attachment revenue, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:6.) The deferred pole attachment revenue regulatory liability requested by PSO is reduced by $788,115 to the June 30, 2017, balance of $0.

Non-AMI Meters

41. THE COMMISSION FURTHER FINDS that PSO is in compliance with Order No. 639314 as to the non-AMI meters. No party objected to including the appropriate amount of non-AMI meter regulatory asset in rate base consistent with Commission Order No. 639314 issued in Cause No. PUD 201300217. The Commission approves the inclusion of the non-AMI regulatory asset in PSO's rate base.

42. THE COMMISSION FURTHER FINDS that regulatory assets, including the non-AMI meters, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The non-AMI meter regulatory asset requested by PSO is reduced by $7,773,107 to the June 30, 2017, net balance of $42,358,000.

43. THE COMMISSION FURTHER FINDS that the non-AMI regulatory asset amortization will change on the date new base rates are implemented in this case and will continue through December 31, 2027.

44. THE COMMISSION FURTHER FINDS and adopts PUD's recommendation to decrease the revenue requirement by $2,219,213 due to correction of Non-AMI Meters Regulatory Asset amortization rate to be based on the net book value of the Non-AMI Meters and amortized through December 31, 2027.

ARO Retired Plant

45. THE COMMISSION FURTHER FINDS that Asset Retirement Obligations ("ARO") recorded pursuant to financial accounting standards. PSO's treatment of ARO obligations in this case is consistent with the treatment in Cause Nos. PUD 200600285, PUD 200800144, PUD 201000050, PUD 201300217 and PUD 201500208. (Hamlett Direct, p. 22, lines 20-23, and p. 23, lines 1-2, and lines 10-20.)

46. THE COMMISSION FURTHER FINDS and accepts the ARO retired plant balance requested by PSO of $539,767.

Deferred Severe Storm Expense

47. THE COMMISSION FURTHER FINDS that regulatory assets, including the deferred severe storm expense, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The deferred severe storm expense regulatory asset requested by PSO is increased by $6,363,372 to the June 30, 2017, balance of $35,363,769.

Customer Deposits

48. THE COMMISSION FURTHER FINDS that a customer deposit represents funds provided by the customer rather than investors. Thus, these funds are used to reduce PSO's rate base. This Commission has consistently treated customer deposits as a reduction to rate base. (Hamlett Direct, p. 33, lines 1-15.)

49. THE COMMISSION FURTHER FINDS that PSO reduced rate base for the $49,674,708 of customer deposits recorded on its books at December 31, 2016, the test year-end.

50. THE COMMISSION FURTHER FINDS that PUD, the Attorney General and OIEC recommended an increase of $986,714 based on the balance of customer deposits at June 30, 2017. According to Mr. Hamlett, adjusting the balance at June 30, 2017, was consistent with PSO's original filing and will result in an additional reduction of $986,714 to PSO's requested rate base. Mr. Hamlett agreed with the adjustment. (Hamlett Rebuttal, p. 26, lines 14-17.) The Commission adopts this adjustment of customer deposits as being appropriate and consistent with how this Commission has treated customer deposits as a reduction to rate base in the past.

Northeastern Unit 4

51. THE COMMISSION FURTHER FINDS that, in PSO's previous rate case, Cause No. PUD 201500208, the Commission deferred consideration on the regulatory treatment of Northeastern Unit 4 because the unit was still in service. "The determination of stranded cost recovery relating to PSO's Northeastern No. 4 Unit should be addressed in PSO's next rate case, following PSO's retirement of Northeastern No. 4 Unit, after Northeastern No. 4 Unit is no longer providing service to the public and is no longer used and useful." (Final Order, Order No. 657877, Cause No. PUD 201500208, p. 10.).

52. THE COMMISSION FURTHER FINDS that PSO retired Northeastern Unit 4, as scheduled, in April 2016, and has no plans to return the unit to service. (Fate Direct Test. at 14:20-21.) Furthermore, PSO is not taking steps necessary to maintain Northeastern Unit 4 to bring the unit back into service at a later date. With each day, the probability of a future return to service diminishes further. However, the Company does not plan to demolish Northeastern Unit 4 as long as Northeastern Unit 3 remains in service (10/30/17 A.M. Tr. at 52:4-20).

53. THE COMMISSION FURTHER FINDS that PSO asserts that the various components of its environmental compliance plan are linked. Each component is part of the overall environmental compliance plan. PSO argued that because the Commission allowed reasonably-incurred costs for the environmental compliance plan to be recovered through base rates by Order No. 657877, then all reasonably-incurred costs to achieve overall compliance should be recovered. Therefore, the Company is requesting the continued recovery of the undepreciated book value of Northeastern Unit 4 as well as a return on the net book value of the asset at the weighted average cost of capital (Fate Direct Test. at 14:8-17). However, as has already been addressed above, the Commission did not in the previous rate case include Northeastern Unit 4 in the environmental compliance plan. In fact, the Commission addressed

Northeastern Unit 4 separately and directed determination of stranded costs be addressed in this Cause, PSO's next rate case.

54. THE COMMISSION FURTHER FINDS that Northeastern Unit 4 provided nearly 36 years of service to PSO customers.

55. THE COMMISSION FURTHER FINDS that initially Northeastern Unit 4 had an established service life of thirty one (31) years. The initial estimate of the life of Northeastern Unit 4 was fairly close to actual life span. In 2006, the Commission established a sixty (60) year service life (10/30/17 A.M. Tr. At 34:14-35:24). Due to environmental, technological and/or physical obsolescence the service life and depreciation rates set in the past were insufficient to allow for a full recovery of the cost of Northeastern Unit 4.

56. THE COMMISSION FURTHER FINDS that it is fair, just and reasonable for PSO to obtain **recovery of** Northeastern Unit 4. using depreciation methods consistent with those recommended in this Cause.

57. THE COMMISSION FURTHER FINDS that the concept of "used and useful" is a fundamental longstanding ratemaking concept in which a utility's opportunity to earn a return is limited to only those assets that are used (i.e., not under construction or standing idle awaiting abandonment) and useful (i.e., actively helping the utility provide efficient service).

58. THE COMMISSION FURTHER FINDS that in Oklahoma, ratepayers are only required to pay rates based upon the value of a public utility's investments that are used and useful in providing service to the public at the time the rates are set. *Turpen v. Oklahoma Corporation Commission,* 1988 OK 126, 769 P.2d 1309, 116 n. 7; *Southwestern Public Service Co. v. State,* 1981 OK 136, 637 P.2d 92, 97. As further explained in Southwestern Public Service Co.:

> In the case of *Oklahoma Natural Gas Co. v. Corporation Commission*, this court said: "In determining whether the rate is reasonable, it is necessary to ascertain the fair value of the property of the appellant used and useful in its public service business at the time the inquiry was made . . . for appellant is entitled to a rate which will yield a fair return upon the reasonable value of the property *at the time it is being used for the public*;" [emphasis added].

Southwestern, ¶ 13, 637 P.2d at 97.

59. THE COMMISSION FURTHER FINDS that Northeastern Unit 4 is not used or useful to PSO customers and PSO should not obtain a return on or **recovery on** Northeastern Unit 4 since Northeastern Unit 4 is not being used to supply power to the public at this time.

<u>Cash Working Capital ("CWC")</u>

60. THE COMMISSION FURTHER FINDS that PSO reduced its rate base by $110,725,044 to reflect the CWC allowance determined by a lead-lag study. (Hamlett Direct, p. 24, lines 14-21.)

61. THE COMMISSION FURTHER FINDS and adopts PUD's recommended methodology to adjust for CWC . After adjustment posed by the ALJ in this report, CWC increases rate base by $3,420,650. (Walkup Responsive, p. 6, lines 1-4 and ALJ Accounting Exhibit attached hereto as Attachment A).

<u>Cost of Capital: Capital Structure, Cost of Debt, Return on Equity & Rate of Return</u>

62. THE COMMISSION FURTHER FINDS the cost of capital for a public utility represents the return on investment the Company has the opportunity to earn from providing service. The cost of capital is typically calculated as the weighted average of debt and equity with weights relying on the capital structure, or percentage of capital from debt and from equity investors (Rush Rev. Req. Resp. Test. at 37:16-38:7).

63. THE COMMISSION FURTHER FINDS that multiple witnesses agreed with the Company's proposed capital structure of 51.5 percent debt and 48.5 percent equity and the proposed cost of debt of 4.60 percent. (Vilbert Rebuttal, p. 2, lines 7-9; Parcell Responsive , p. 2, lines 20-24; Reno Responsive, p. 4, lines 5-6; Griffing Responsive, p. 38, lines 11, 17; Rush Responsive, p. 6, lines 18-20.) No party objected to PSO's proposed capital structure. The Commission adopts PSO's proposed capital structure of 51.5 percent debt and 48.5 percent equity.

64. THE COMMISSION FURTHER FINDS that PSO's Application proposes the adjusted test year long-term debt costs of 4.60 percent. No party contests this cost of debt. The Commission finds that PSO's embedded cost of long-term debt is 4.60 percent.

65. THE COMMISSION FURTHER FINDS that the return on equity represents one of the most difficult values in a rate case proceeding because it must be estimated using expert witnesses' models and judgment. (Griffing Resp. Test. at 10:6-13; Parcell Rev. Req. Resp. Test. at 20:6-10.) The resulting return on equity must offer the public utility the opportunity to earn a fair return on its investment, allowing a return similar to returns on other similarly risky investments, providing confidence in the financial integrity of the company, and allowing the company to attract capital. *See Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

66. THE COMMISSION FURTHER FINDS that in this Cause, most expert witnesses presented the results of various Discounted Cash Flow ("DCF") models and models derived from the Capital Asset Pricing Model ("CAPM"). (Griffing Resp. Test. at 10:9-11, 28:3-34:19; Vilbert Dir. Test. at 38:21-23, 47:9-21; Parcell Rev. Req. Resp. Test. at 20:9-10.) Some witnesses compared those results to the rates of return awarded in other regulatory jurisdictions over a recent period of time. (Griffing Resp. Test. 35:4-36:7; Parcell Rev. Req. Resp. Test. at 28:29-31.)

67. THE COMMISSION FURTHER FINDS that to estimate the return on equity using either a DCF model or models derived from CAPM, the experts first developed a set of comparison companies with risks and operations similar to PSO. (Griffing Resp. Test. at 12:8-18; Vilbert Dir. Test. at 30:8-15; Parcell Rev. Req. Resp. Test. at 20:14-21:6; Rush Rev. Req. Resp. Test. at 17:4-13.) For the DCF, the experts calculated the dividend yield for each

comparison company, then adjusted the yield to include a growth rate. (Griffing Resp. Test. at 10:15-11:7; Vilbert Dir. Test. at 36:5-13; Parcell Rev. Req. Resp. Test. at at 21:28-22:3.) The experts differed on the growth rates used, although many favored the use of analysts' estimates of forward-looking growth rates. (Griffing Resp. Test. at 22:2-23:8; Vilbert Dir. Test. at 37:25-38:4; Parcell Rev. Req. Resp. Test. at 23:4-13; Rush Rev. Req. Resp. Test. at 23:9-10.) The experts could then average the results of these return values across all comparison companies to generate a return on equity result.

68. THE COMMISSION FURTHER FINDS that even though the experts differed on the comparison companies used and in the manner some calculations were performed, many of the experts' results from the DCF model calculated in the above manner fall in a similar range from 8.54 to 8.83 percent. (Griffing Resp. Test. at 27:14-15; Vilbert Dir. Test. at App. C, 36, Schedule No. MJV-6; 11/1/17 Early P.M. Tr. at 28:20-29:14, 92:3-93:17; Rush Rev. Req. Resp. Test. at 16-18.) The biggest difference between the final recommendations arises in part from Dr. Vilbert, the expert for PSO, using what he calls the financial risk adjustment. (11/2/17 Late P.M. Tr. at 20:7-11.)

69. THE COMMISSION FURTHER FINDS that the other ROE expert witnesses in this Cause disagreed with Dr. Vilbert's financial risk or leverage adjustment. (Griffing Resp. Test. at 42:16-43:21; Parcell Rev. Req. Resp. Test. at 34:20-35:7.) Mr. Parcell, for example, explained that equating comparison companies' market-based capital structures with PSO's book-value capital structure would result in a significantly higher return on equity. (Parcell Rev. Req. Resp. Test. at 35:4-14.) Further, it was established on cross-examination that Dr. Vilbert's adjustment was "not typically used in regulatory proceedings like this one" and that he could not provide any examples of the adjustment being used in Oklahoma or even by a public service commission in the continental United States. (11/1/17 Early P.M. Tr. at 30:13-14, 54:5-58:6, 63:14-17.) He agreed that before the adjustment, his simple DCF model produced an estimated return on equity of 8.8 percent. (11/1/17 Early P.M. Tr. at 93:10-13.)

70. THE COMMISSION FURTHER FINDS that the ROE expert witnesses disagreed on the significance of recently awarded returns on equity from other jurisdictions. Dr. Vilbert represented that these results were around 9.5 percent, meaning that the Commission should award a return higher than 9.5 percent. (Vilbert Reb. Test. 10:7-21.) The other experts argued that recently awarded returns on equity were in a range from around 9.0 percent to around 10.0 percent, meaning that returns around 9 percent were reasonably close to recently awarded returns. (Griffing Resp. Test. at 37:3-12; Parcell Rev. Req. Resp. Test. at 31:10-20.)

71. THE COMMISSION FURTHER FINDS that the financial risk or leverage adjustment recommended by PSO's witness, Dr. Vilbert, is rejected. The adjustment is not currently accepted in regulatory proceedings in the United States and tends to over-state the required return on equity.

72. THE COMMISSION FURTHER FINDS that the return on equity recommendations by a majority of ROE experts are largely concentrated around 8.83 percent to 9.0 percent. For example, Dr. Griffing recommended a reasonable range of exactly that amount, while Mr. Parcell recommended a 9.0 percent return on equity and Mr. Rush recommended 8.9 percent. The Commission therefore adopts a 9.0 percent as the return on equity in this cause.

73. THE COMMISSION FURTHER FINDS that the overall rate of return that results from the capital structure and cost of capital determined above is 6.73 percent. (Exhibit 65, p. 33.)

Description	Capital Ratio	Cost Rate	Weighted Average Cost
Long Term Debt	51.49%	4.60%	2.37%
Common Equity	48.51%	9.00%	4.37%
Total Capital	100%		6.73%

Payroll

74. THE COMMISSION FURTHER FINDS that PSO proposes an increase to test year levels of payroll in the amount of $2,726,115.00 for PSO and $2,773,667.00 for American Electric Power Service Company ("AEPSC") payroll. (Exhibit 66 p. 55.) To determine the appropriate payroll level for PSO, the Company used the base payroll amounts for each employee at test year end, a known and measurable amount. That amount was then increased by 3.5 percent to reflect the known and measurable pay increase for 2017 that has been implemented. (Hamlett Rebuttal, p. 18, lines 9-15, and Exhibit 138, p. 29) PSO's adjustment recognized the normal turnover of employees during the test year because it used the test year-end employees and their actual salary at year-end before applying the known and measurable 2017 pay increase. (Hamlett Rebuttal, p. 30, lines 6-9.)

75. THE COMMISSION FURTHER FINDS that PSO competes in a national labor market against regulated and unregulated companies, as well as AEP's own internal system for highly trained, specialized and mobile personnel. PSO has found it more effective to pay a consistent, nationally competitive rate across its system, which is typical practice for other companies of AEP's size and geographic diversity. (Tr. 11/1 AM at pp. sd-99, lines 1-24; sd-100, line 24 to sd-101, line 8.)

76. THE COMMISSION FURTHER FINDS that PUD reviewed PSO's proposed adjustment to increase O&M expenses to reflect base payroll in the amount of $2,727,075. According to Mr. Rush the adjustment included the raises implemented in April 2016 and in the fall of 2016, and raises implemented in April 2017, and for the fall of 2017. (Rush Responsive, p. 41, lines 13-18.) According to Mr. Rush, PSO's workpapers complied with the Commission's rules and annualized the level of salaries and wages, and PUD did not have any adjustments to make after its review of payroll expense. (Rush Responsive, p. 42, lines 10-12.)

77. THE COMMISSION FURTHER FINDS that PSO provided WP H-4-6, Wage and Salary Surveys, as required by OAC 165:70-5-22(4). No party opposed these Wage and Salary Surveys which guide PSO's compensation levels. PUD, after review of this information, made no adjustment, finding that:

> The Company needs employees with a particular set of experience, knowledge, and skills to provide efficient and affordable electric service to its customers. As such, PUD believes that it is prudent for the Company to have a robust payroll

> plan as an important part of employee attraction and retention. In addition, after reviewing the surveys provided by Willis Towers Watson, PUD believes that the compensation practices of the Company are aligned with the compensation practices of its peer group.

Rush Responsive at p. 42, lines 2-8.

78. THE COMMISSION FURTHER FINDS and approves PSO's requested payroll expenses as guided by the Wage and Salary Surveys, including the amounts billed to PSO by AEPSC, because it is a known and measurable change that recognizes actual employees and their salaries at the end of December 2016 and approved raises in 2017 that have been implemented.

Supplemental Executive Retirement Plan ("SERP")

79. THE COMMISSION FURTHER FINDS that it has consistently disallowed recovery of SERP costs in previous rate cases involving PSO. (Cause No. PUD 200600285, Cause No. PUD 200800144, and Cause No. PUD 201500208.) SERP expenses are consistently disallowed in other jurisdictions. (Exhibit 66, p. 45.) As stated in Order No. 658529 in Cause No. PUD 201500208, the Commission finds that for rate-making purposes, utility shareholders should bear the additional costs associated with supplemental benefits to executives.

80. THE COMMISSION FURTHER FINDS and disallows SERP costs in this Cause based on the premise that ratepayers should pay for all of the executive benefits included in the Company's regular pension plans while shareholders should pay for the additional benefits included in the supplemental plan. Mr. Farrar and Mr. Garrett both recommended that PSO's requested non-qualified pension expense be borne by the shareholders. (Farrar Rev. Req. Resp. Test. at 23:12-18; Rev. Req. Resp. Test. at 46:3-6.) The employees that receive this benefit are highly compensated to align their interests with shareholders. (Garrett Rev. Req. Resp. Test. at 46:6-14) Therefore, the Commission finds that SERP expense in the amount of \$96,780.00 for PSO and \$253,082.00 for AEPSC are excluded from PSO's rates.

Incentive Compensation—short term and long term

81. THE COMMISSION FURTHER FINDS that witnesses, Mr. Farrar and Mr. Garrett both recommended adjustments to the Company's incentive compensation plans. (Farrar Rev. Req. Resp. Test. at 21:17-19; Garrett Rev. Req. Resp. Test. at 32:15-17.) Mr. Farrar recommended that 50 percent of the annual incentive plan be excluded from rates and Mr. Garrett recommended that 75 percent of those costs be excluded. Mr. Farrar testified that 75 percent of the test year level of the incentive plans funding was based on the Company's operating earnings per share in 2016, and that this was reduced to 70 percent for 2017. (11/6/17 Early P.M. Tr. at 92:9-12.) Mr. Farrar testified that according to the Company's 2017 Proxy Statement, the award level for that financial component was 195.5 percent of the target level in 2016. (11/6/17 Early P.M. Tr. at 92:15-19.) Mr. Carlin of PSO testified that the operating earnings per share threshold for 2017 was \$3.55 per share. (11/1/17 A.M. Tr. at 79:16-17.) This is a reduction from the \$3.65 operating earnings per share threshold for the previous year, 2016. (11/6/17 Early P.M. Tr. at 16:9-13.) Mr. Farrar testified that the actual impact of this financial component on bonuses could be 140 percent of the target level, and that would certainly be

understood by PSO's employees. (11/6/17 Early P.M. Tr. at 93:3-6). Even though the financial aspect of the annual incentive plan clearly produced most of the incentive plan's cost, Mr. Farrar limited his adjustment to 50 percent of the target level because it had been the Commission's practice to share the costs evenly between shareholders and ratepayers. (Farrar Rev. Req. Resp. Test. at 21:17-19.)

82. THE COMMISSION FURTHER FINDS that the annual incentive plan expenses be reduced by $4,863,954 to exclude 50 percent of the target level of this expense from the revenue requirement.

83. THE COMMISSION FURTHER FINDS that Mr. Farrar and Mr. Garrett both recommended adjustments to exclude 100 percent of the long-term incentive plan costs from rate recovery. (Farrar Rev. Req. Resp. Test. at 22:12-13; Garrett Rev. Req. Resp. Test. at 40:13-18.) The long-term incentives are provided to highly compensated employees to align their interests and loyalty to shareholders. (Garrett Rev. Req. Resp. Test. at 40:15-41:3.) These costs are not essential to serve the ratepayer and should be excluded from rate recovery. The performance measures used in the long-term incentive program are based on achieving financial goals that benefit shareholders and thus should not be borne by ratepayers. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of shareholders first.

84. THE COMMISSION FURTHER FINDS that the adjustment recommended by the Attorney General and by OIEC to reduce expenses by $3,106,766 is adopted.

<u>Capitalized Incentives</u>

85. THE COMMISSION FURTHER FINDS that there is no finding in the Cause that PSO's incentive compensation costs are unreasonable and therefore declines to adopt the adjustment proposed by OIEC witness Mark Garrett to reduce rate base by $37,645,259 for capitalized incentives. (Garrett Responsive, p. 12.)

<u>Dues and Donations and credit line fee expense</u>

86. THE COMMISSION FURTHER FINDS that the following PUD adjustments be adopted:

a. PUD's recommendation that the Commission accept PSO's proposed adjustment No. WP H-2-27 to decrease PSO's cost of service by $173,678 to exclude expenses that are not allowed for ratemaking purposes. (Aguirre Responsive Testimony, filed September 21, 2017, pages 6-8.)

b. PUD's adjustment to No. H-2 to decrease Dues and Donations by $117,876. (Aguirre Responsive Testimony, filed September 21, 2017, pages 8-9.)

c. PUD's recommendation that the Commission accept PSO's proposed $678,104 adjustment No. WP H-2-9 to reclassify Credit Line Fee Expense to

Administrative and General Expense. (Aguirre Responsive Testimony, filed September 21, 2017, pages 9-13.)

Factoring

87. THE COMMISSION FURTHER FINDS THAT Factoring Expense is expense associated with the collection of billed revenue and is determined based upon the Company's revenue. The Commission accepts PUD's recommendation to decrease the Factoring Expense in the amount of ($1,244,786).

New Storm Costs

88. THE COMMISSION FURTHER FINDS that PSO proposes to increase storm damage expense by $8,264,000.00, from $2,936,000.00 to $11,200,000.00 (Hamlett Direct p.8 Lines 1-10), which is the seven-year average experienced by the Company for storm expense from 2010 through 2016.

89. THE COMMISSION FURTHER FINDS that the Attorney General opposed this for three reasons: (1) PSO has made significant investments to its distribution system, (2) a lower base rate allowance with a later recovery of additional expenses ensures PSO has appropriate incentives to minimize storm damage recovery expenses, and (3) it is an inappropriate time to request recover for uncollected storm damage expenses and to increase the base rate allowance. (Alexander Rev. Req. Resp. Test. at 5:9-18.) The Attorney General noted that this recommended treatment was continued in PSO's last rate case, PUD 201500208.

90. THE COMMISSION FURTHER FINDS that there is no need to increase base rates based on anticipated and/or unknown increases in storm damage expense in the future. The Commission finds that it is reasonable to leave the current level of storm damage expense in place. An increase in base rates is not necessary as the Company is insulated from under-recovery of storm damage expense through its tracker mechanism.

SPP Fees and Expenses

91. THE COMMISSION FURTHER FINDS that the Attorney General and OIEC both recommended adjustments to reduce the level of SPP fees and expenses requested by the Company. (Farrar Rev. Req. Resp. Test. at 27:6-14; Garrett Rev. Req. Resp. Test. at 66:7-11.) Mr. Farrar testified that the Company did not support the increase in the SPP Schedule 9 NITS (Network Integration Transmission Service) charges for affiliates. (Farrar Rev. Req. Resp. Test. at 26:9.) Under cross-examination, Mr. Hamlett of AEP admitted that these cost increases were not effective within the six-month post-test year end date. (10/30/17 Early P.M. Tr. at 69:10-19.) PUD also testified that the effective date of the requested increase in Schedule 9 NITS transmission expense was not effective within the test year or the six-month post-test year period. (Nov. 7, 2017 Tr. at KA100.)

92. THE COMMISSION FURTHER FINDS and adopts the Attorney General's adjustment to reduce the SPP Schedule 9 NITS charges by $13,994,625.

Generation O & M Normalization

93. THE COMMISSION FURTHER FINDS that PSO proposed an adjustment to normalize generation O&M expenses by using a three-year average of the expenses, adjusted to remove the costs for the retired Northeastern Unit 4. (Slater Dir. Test. at 11:3-5.) Mr. Farrar and Mr. Garrett recommended the rejection of this adjustment. (Farrar Rev. Req. Resp. Test. at 25:5-7; Garrett Rev. Req. Resp. Test. at 60:7-9.) Mr. Farrar testified that the expense had been declining during the period in question and for that reason a normalization adjustment was not indicated. (Farrar Rev. Req. Resp. Test. at 24:14-25:2.) The O&M expense has been declining in recent years, which would indicate that the test year level is appropriate for recovery in this instance. OIEC also argued that PSO did not provide any support to justify a normalization adjustment.

94. THE COMMISSION FURTHER FINDS and rejects PSO's adjustment to normalize this generation expenses. The Commission adopts the recommendation of the Attorney General and OIEC and rejects an increase of $2,110,317 to the test year production O&M.

Ad Valorem Taxes

95. THE COMMISSION FURTHER FINDS that PUD and the Attorney General recommended an adjustment to current Property/Ad Valorem Taxes to reflect PUD's recommended adjustments to the net plant in service as of the six-month post test year, June 30, 2017, resulting in a decrease of ($49,673).

Rate Case Expense

96. THE COMMISSION FURTHER FINDS that PSO has requested recovery of its incremental estimated cost for this proceeding of $1,071,350; $300,000 of Independent Evaluator expenses granted in Cause No. PUD 201600300; and a true up over-recovery of ($210,284) from prior base rate cases (Cause Nos. PUD 201300217, PUD 201500208). These three items total $1,161,066 which PSO proposed to recover over a two-year period with an annual cost-of-service amount of $580,533. (Hamlett Rebuttal, p. 50, lines 17-22.)

97. THE COMMISSION FURTHER FINDS that OIEC was the only party to present a witness that took issue with PSO's rate case expense request. Mr. Mark Garrett had a two-part recommendation wherein he recommended a reduction in PSO's recovery of costs for the current proceeding from $1,161,066 to $590,566, a reduction of almost fifty percent. (Mark Garrett Responsive, p. 51, lines 14-17.) Mr. Garrett testified that the rate case costs were overstated due to what he considered to be excessive outside legal fees; above market fees for PSO's return on equity witness; the cost of the demolition study; and the estimate for notice cost of $43,500. Second, he recommended a four-year recovery period rather than a two-year recovery period requested by PSO. (Mark Garrett Responsive, p. 51, lines 17-20.)

98. THE COMMISSION FURTHER FINDS that the evidence showed the actual expenses for outside counsel in PUD 201300217, which was a settled case, totaled $306,406 as compared to $619,690 for a fully litigated case over an extended period of time in Cause PUD

201500208. The estimate in the current case is between those two actual amounts. The estimate for the ROE witness of $150,000 is consistent with the actual cost incurred by PSO in Cause No. PUD 201500208 of $147,530. Regarding the notice, PSO's actual charges in Cause Nos. PUD 201300217 and PUD 201500208 were $30,842 and $43,531 respectively, which is consistent with the current estimate of $43,500. (Hamlett Rebuttal, p. 52, lines 2-14.) No party contested the actual expenses incurred from the previous two cases.

99. THE COMMISSION FURTHER FINDS that rate case expense costs should be scrutinized more closely than they have been in the past. Moreover, utilities should understand that not all rate case costs should be borne by ratepayers. Necessary and reasonable costs to process a rate case should be borne by ratepayers. Ratepayers should not be burdened with unreasonably inflated legal costs and expert witness fees, especially when the testimony of some expert witnesses may appear to be duplicative and/or unnecessary testimony.

100. THE COMMISSION FURTHER FINDS that rate case expense costs related to relitigation of previously settled issues shall be reviewed by PUD. PUD shall provide testimony as to specific testimony offered by an expert witness as to any new evidence not presented in previous rate cases and any change of circumstances.

101. THE COMMISSION FURTHER FINDS that two rate case expenses in the current rate case proceeding call for separate consideration. First, Mr. Meehan acknowledged in sworn testimony that his work on decommissioning in this case involved only an update to prior studies, not a full study. (11/3/17 Early P.M. Tr. at 81:16-25.) Yet the rate case expense for Mr. Meehan remains quite high and seems to indicate an expense for a full study. (Exhibit MG-2.7.) Ratepayers should not pay the expense of a full study when the actual product is an update of a previous study. Secondly, the ALJ (not a party) recommends the disallowance of witness fees for PSO witness Quackenbush. The ALJ offers this witness as an example of an expert witness that offered unnecessary testimony that contributed no value to the proceedings. Mr. Quackenbush provided a mere five pages of testimony filed on October 11, 2017. Such testimony contained no workpapers, empirical analysis or independent financial analysis. (10/30/17 A.M. Tr. at 119:10-124:18). PSO did not rely upon this witness as to any issue as is evidenced by a lack of even a mention of this witness's testimony in PSO's filed proposed findings of fact and conclusions of law.

102. THE COMMISSION FURTHER FINDS that although various parties have recommended a three or four-year amortization, the Commission will proceed with a two-year amortization that reflects the current timing of rate case filings. If rate cases continue to be brought every two years then a longer amortization will result in excessive overlap of rate case expenses.

103. THE COMMISSION FURTHER FINDS that the Company's requested costs for legal fees, witnesses, notice, and other rate case expenses be allowed. However, the Commission directs that witness fees and expenses of witness Quackenbush, an unnecessary witness that contributed nothing of substance to these proceedings, not be paid by customers but by shareholders. The Commission directs that the Company's overall rate case expenses be collected over a two-year period.

Depreciation

104. THE COMMISSION FURTHER FINDS that some parties raised a number of issues pertaining to the lack of credibility of PSO witness Mr. Spanos's data and study. Attorney General witness Mr. Dunkel testified that for Account 367 Underground Conductors and Devices, Mr. Spanos made undisclosed changes to what is supposed to be the historic data, which records how long investments have actually lived in the past. Chart 3 on page 32 of Mr. Dunkel's responsive testimony shows the difference in the data through the year 2014 used by Mr. Spanos in this proceeding compared to the data through the year 2014 used by Mr. Spanos in the prior PSO rate case proceeding. Not only did Mr. Spanos change the historic data, but he did not disclose that he had altered it. (11/3/17 Early P.M. Tr. at 6:18-20; 11/3/17 A.M. Tr. at 80:10-14). Such changes to historical data is not typical and should be disclosed by expert witnesses. Discussing Mr. Spanos's undisclosed change in data in Account 367, OIEC witness David Garrett stated, "[f]ortunately for all of us, there was a witness in this case, Mr. Dunkel, that did catch that." (11/3/17 A.M. Tr. at 62:19-22).

105. THE COMMISSION FURTHER FINDS that it is clear that PSO's witness Mr. Spanos made changes to the historic data in Account 367 and did not disclose these unusual changes. It is also clear that Mr. Spanos did not disclose that he had altered the data until the Attorney General had discovered the alteration and asked about it in discovery. The record shows that the difference between a 65 year average service life, which is what Mr. Spanos recommended in the prior case before altering the data, and the 45 year average service life Mr. Spanos recommends in this case after altering the data, is in excess of $4 million per year. (Dunkel Resp. Test. at 33). Additionally, there were irregularites in Mr. Spanos's cited rates approved in prior proceedings as well as the industry range of lives used. (11/3/17 A.M. Tr. at 102:6-24 and 11/3/17 Late P.M. Tr. at 25:8-17; Hearing Exhibit 49).

106. THE COMMISSION FURTHER FINDS that the depreciation study proposed by PSO is rejected. Furthermore, the Commission adopts the Attorney General's life and Iowa curve combination recommendations.

107. THE COMMISSION FURTHER FINDS that the Attorney General's total demolition cost estimates are reasonable and appropriate and therefore adopt them in this Cause. Furthermore, the Commission rejects Mr. Spanos's escalation of the production plant demolition cost estimates.

108. THE COMMISSION FURTHER FINDS that the Attorney General witness Mr. Dunkel used the same net salvage method the Commission had adopted in the 2008 PSO rate case. In that proceeding, the Commission adopted the Attorney General's proposed depreciation rates, which used the average of net salvage dollar amounts from recent years. (11/3/17 Late P.M. Tr. at 71:13-72:8; 11/3/17 Late P.M. Tr. at 89:7-92:2).

109. THE COMMISSION FURTHER FINDS that, based upon the record of this Cause, the depreciation rates and associated parameters recommended by the Attorney General are adopted.

110. THE COMMISSION FURTHER FINDS that at the request of PSO, Mr. Spanos did not include Account 303 in his depreciation study. (11/3/17 A.M. Tr. at 69:10-14, 70:8-9.). Because it was not part of the depreciation study, the Attorney General did not address Account 303. However, OIEC witness Mr. David Garrett did. On pages 46 through 49 of Mr. Garrett's responsive testimony on depreciation, Mr. Garrett stated that this account includes PSO's software. He recommended a 10-year amortization period instead of the 5-year amortization period PSO proposed. Mr. Garrett's analysis was clear and convincing. Mr. Garrett testified that his recommendation reduces PSO's depreciation expense by $4,993,173 per year. Based upon the evidence in the record, the Commission accepts the recommendation of Mr. David Garrett pertaining to Account 303.

<u>Base Revenue</u>

111. THE COMMISSION FURTHER FINDS that the Attorney General's witness, Mr. Farrar, recommended that PSO's base revenue be updated to June 30, 2017. (Farrar Rev. Req. Resp. Test. at 12:11). Mr. Farrar based his recommendation on information provided by PSO, adopted for consistency with PSO's test year-end annualized base revenue. (Farrar Rev. Req. Resp. Test. at 12:14-13:21). PSO had provided three different base revenue update adjustments that were inconsistent with the methodology originally used by the Company. (11/8/17 Early P.M. Tr. at 81:25-87:7). The Company at one point stated that its update was an estimate. (11/8/17 Early P.M. Tr. at 85:22-86:1). The final adjustment produced by the Company was provided two weeks before the beginning of the hearing on the merits, and therefore was un-vetted by the parties to this Cause. (11/8/17 Early P.M. Tr. at 87:4-14). Therefore, the Commission adopts the Attorney General's recommended adjustment to update non-fuel base revenue to June 30, 2017, which increases base revenue by $505,152 be adopted by the Commission.

<u>Energy Efficiency/Demand Response</u>

112. THE COMMISSION FURTHER FINDS that PUD witness, Ms. Champion, recommended that PSO's adjustment to reduce revenue for energy efficiency programs be rejected. (Champion Rev. Req. Resp. Test. at 9:3-6). Ms. Champion stated that, in effect, PSO had adjusted the revenue reduction a full year outside the test year. (Champion Rev. Req. Resp. Test. at 9:11-14). Ms. Champion testified that PSO would not be denied the lost net revenue recovery for the January through June period if PSO's adjustment is denied. (Champion Rev. Req. Resp. Test. at 13:13-20). Therefore the Commission adopts PUD's recommendation that PSO's projected revenue loss be rejected, and that PSO's adjusted revenue be increased by $2,707,619.

<u>Elimination of SRR and AMI Riders</u>

113. THE COMMISSION FURTHER FINDS that PSO proposed the elimination of two riders, the System Reliability Rider and the Advanced Meter Infrastructure Rider. (Champion Rate Design Resp. Test. at 8:1-4.) Moving the recovery of these costs to base rates will be revenue neutral for both the Company and ratepayers. No party challenged those calculations, which move $23,790,724 from riders to base rates, as noted in the accounting exhibit. Therefore, these two riders are moved from riders to base rates as proposed by PSO.

Fuel Procurement and Handling Expense

114. THE COMMISSION FURTHER FINDS that the Attorney General recommended moving PSO's fuel procurement, unloading and handling (fuel handling) costs out of the FCA and into base rates. PSO witness Fate stated that fuel handling costs were included in base rates until May 2015 when they were moved to the FCA to comply with Order No. 639314 issued in Cause No. PUD 201300217. The change was initially recommended by PUD and was agreed to by all parties who signed a stipulation in that case which included the AG's office. (Fate Rebuttal, COS, p. 9, lines 12-17.)

115. THE COMMISSION FURTHER FINDS that Mr. Fate testified that PSO's test year fuel handling costs in Cause No. PUD 201300217 were approximately $4.8 million as compared to $3.2 million in this cause. If fuel handling costs were still recovered in base rates, customers would not have realized the $1.6 million decrease that occurred between the 2013 case and current rate case. (Fate Rebuttal, COS, p. 10, lines 5-7.)

116. THE COMMISSION FURTHER FINDS that the fuel handling costs shall remain in the FCA as this Commission has determined that all fuel costs should be in the FCA and not in base rates.

Off System Sales

117. THE COMMISSION FURTHER FINDS that currently Off System Sales ("OSS") allows for PSO's retention of 10 percent of OSS margins while sharing 90 percent of OSS margins with customers. (Hakimi rebuttal p. 3 ln 5-8).

118. THE COMMISSION FURTHER FINDS that OIEC recommends modification of PSO's FCA rider to exclude net revenues earned from SPP energy sales from the margin sharing provision that currently applies to off system sales. (Exhibit 118, pp. 14-15). The AG recommends no sharing of off-system sales so that 100 percent of any off-system sales margins will be credited to PSO ratepayers. (Exhibit 119, p. 3). Both the Attorney General and OIEC testify that the SPP Integrated Market Place now handles dispatch of units within the region and that the market rates provided by the SPP Integrated Market Place allow for an accurate check to the costs accrued by PSO. (See Exhibit 119, p. 3 and Exhibit 118, p. 14). Also, the Attorney General notes that neither OG&E nor the Empire District Electric Company gain a return on OSS in their respective fuel adjustment clauses. OG&E ended its off system sales on electricity rider as part of the settlement in OG&E's 2011 rate case. (Exhibit 119, p. 7). PUD supported OIEC's position. (Rush, Rate Design Rebuttal, p. 12, line 4).

119. THE COMMISSION FURTHER FINDS that PSO offered testimony that AEPSC's Commercial Operations, on behalf of PSO, optimizes the value of PSO's generation by participating in both the SPP Integrated Market Place Energy markets and the Operating Reserve markets. The optimization strategy extends beyond PSO's participation in SPP Integrated Market Place day ahead and real-time markets. (Hakimi Rebuttal, p. 6, lines 1-11). The SPP is tasked first with maintaining reliability, and then with matching generation supply with load demand based on market prices. According to PSO, the Attorney General's description of the SPP Integrated Market Place severely over stated the role of SPP in regards to the optimization

of PSO's OSS margins, while at the same time failed to recognize the major role of AEPSC and PSO personnel in all phases of the SPP Integrated Market Place. PSO offered testimony that keeping the OSS margin sharing in place will continue to provide incentives to PSO to maintain and operate its generating fleet so it will take full advantage of the market for the benefit of its customers. (Hakimi Rebuttal, p. 4, lines 7-16).

120. THE COMMISSION FURTHER FINDS that the volume of information that has to be submitted to the SPP Integrated Market Place and retrieved after the market has cleared has increased significantly. Participation in the SPP Integrated Market Place has lead to significantly more labor required to prepare the bids and assess the results so that PSO can be ready to implement the market results. In addition to the day-ahead energy market that did not previously exist, there are four new markets for the ancillary services in the day-ahead and the real-time markets. For the day-ahead market alone, eighty-eight (88) data points have to be submitted to SPP for each generating unit for a given day. (Hakimi Rebuttal, p. 8, lines 10-19).

121. THE COMMISSION FURTHER FINDS that the current OSS margin sharing of 90 percent to the customer and 10 percent to PSO should continue. It is clear that the advent of the SPP Integrated Market Place has changed the way PSO operates its system but it has also brought more complexity to the transactions which currently make up OSS activity. Additionally, the current OSS sharing will continue to emphasize aggressive pursuit of off-system sales for the benefit of both customers and the company.

Fuel Adjustment Clause

122. THE COMMISSION FURTHER FINDS that OIEC recommended certain revisions to PSO's FCA Rider to include an annual filing by PSO and provisions for notice and a hearing if requested by a party. (Norwood Responsive, p. 6, line 16 – p. 7, line 2). OIEC further recommended that the monthly fuel reports be provided electronically to all parties who have participated in PSO's most recent base rate proceeding at the same time the reports are provided to the PUD staff and that the current provision that allows PSO to make interim adjustments to the FCA factor be eliminated. (Norwood Responsive, p. 7, lines 2-9).

123. THE COMMISSION FINDS that PSO, via sworn testimony, agreed to make the same information that is provided to PUD for a proposed fuel factor adjustment available to other parties. Additionally, whenever PSO makes a decision to propose a new fuel factor, at the same time PSO notifies PUD, PSO will notify those parties that have expressed an interest and make arrangements for them to come on site to review the confidential information. (Tr. 11/8 PM, SJ6, lines 16-24). PSO is willing to change the annual fuel factor determination from November to October. PSO was also willing to send the monthly fuel letter to interested parties at the same time it is sent to PUD. (Tr. 11/8 PM, SJ4, lines 21-22). The Commission's expectation is that PSO abide by this agreement made via sworn testimony.

124. THE COMMISSION FURTHER FINDS that the current review process should be kept in place and not require the opening of a formal docket with possible additional hearings. PSO's agreement to supply both the monthly fuel letter and the information on fuel factor changes (both the annual and any interim fuel factor) to requesting parties is reasonable and should supply interested parties with the information that they need. Opening a formal docket

for setting a fuel factor is not merited. The Commission declines to adopt OIEC's proposed revisions to PSO's FCA Rider.

SPPTC Tariff Modifications

125. THE COMMISSION FURTHER FINDS that OIEC proposed three modifications to PSO's existing Southwest Power Pool Cost Tracker ("SPPTC") tariff. The three proposed modifications are summarized as follows:

A. First: OIEC witness, Mr. Norwood, recommended that annual revisions to the SPPTC tariff be made subject to review and approval by this Commission. (Exhibit 118, p. 18). Mr. Norwood recommended that PSO file an application to revise the SPPTC each year sixty days prior to the first billing cycle in October when the proposed rates are expected to be placed in effect. (*Id.*).

B. Second: Mr. Norwood's second proposed modification to the SPPTC tariff would make it explicit that the Company has an ongoing obligation to provide support for the reasonableness of third party charges recovered through the SPPTC in future base rate proceedings. (*Id.* at 19).

C. Third: Mr. Norwood's third proposed modification to the SPPTC tariff is to eliminate the provision in the SPPTC tariff authorizing interim adjustments at any time when an over or under recovery of expenses exceeds 10 percent since the SPPTC tariff already provides for addressing over and under recoveries of SPPTC costs in a future base rate proceeding. (*Id.* at 20).

126. THE COMMISSION FURTHER FINDS that PSO agreed to Mr. Norwood's second revision which was to require PSO to provide testimony in every base rate case addressing the reasonableness of the third-party charges recovered through the SPPTC Tariff. (Fate Rebuttal, p. 8, lines 10-12). PUD witness Chaplin agreed with Mr. Norwood's second recommendation that the Company has an ongoing obligation to provide testimony to address the reasonableness of third party charges recovered through the SPPTC and future base rate proceedings. (Chaplin Rebuttal, p. 6, lines 8-10). The Commission, therefore, adopts Mr. Norwood's second proposed modification to the SPPTC tariff.

127. THE COMMISSION FURTHER FINDS that PUD testified that Mr. Norwood's first proposed modification to the SPPTC, requiring the Company to file an application with the OCC to revise the SPPTC tariff each year, should not be adopted because PSO's current annual redetermination process provides for an adequate level of review. (Chaplin rebuttal p. 5 ln 16-p.6 ln 6). Furthermore, PUD testified that Mr. Norwood's third proposed modification to the SPPTC, to eliminate the current provision for the Company to implement interim adjustments to the SPPTC tariff at any time when an over-recovery or under-recovery of expenses exceeds 10 percent, should not be adopted because the 10 percent over-under provision, the annual re-determination process, and reviews in future base rate proceedings provide reasonable protections to customers by allowing multiple opportunities for review, not just review in future rate proceedings. Additionally, PSO provided agreement via sworn testimony to timely share the

SPPTC information that is provided to PUD for review to interested parties. For these reasons the Commission rejects Mr. Norwood's first and third proposed modifications to the SPPTC.

128. THE COMMISSION FINDS that PSO has added to the SPPTC that would require broader review if annual increase exceeds 50 percent. OIEC requests the Commission not adopt this added provision. This issue was litigated in the previous PSO rate case. PUD witness Mr. Chaplin testified that this added provision provides another mechanism for PUD to ensure customer protection while also incentivizing PSO to continually pursue cost control within the SPP organizational structure. (Chaplin rebuttal p. 8 ln. 18- p.9). The Commission confirms its previous decision on this specific issue and further, in this Cause, again adopts this added provision.

Tax Adjustment Rider

129. THE COMMISSION FURTHER FINDS that PSO requested that the Tax Adjustment ("TA") Rider be modified to include an ad valorem tax adjustment factor that would be adjusted annually to account for the difference in ad valorem property taxes expensed above or below the amount included in base rates. The ad valorem tax adjustment would be allocated to ratepayers in the same manner as ad valorem taxes are currently being recovered from ratepayers through base rates and recovered on a kwh basis (Jackson Direct Test. at 22:10-18).

130. THE COMMISSION FURTHER FINDS that the AG witness, Mr. Bohrmann, recommended that the Commission reject the Company's proposed change to its TA Rider for several reasons. First, PSO's proposed change to its TA Rider does not pass the well-established three-prong test used to determine whether a cost should be eligible for recovery through an adjustment mechanism outside of base rates. Mr. Bohrmann explained that property (ad valorem) taxes are 1) not substantial; 2) not volatile; and 3) within PSO's control (Bohrmann Rate Design Resp. Test. at 13:1-4). Mr. Bohrmann also identified three structural flaws with the Company's proposed change to its TA Rider. First, he explained that the proposed change only examines the change in one specific cost type - property (ad valorem) taxes - without examining the extent to which all of the Company's costs recovered through base rates may change. Second, he noted that the proposed change does not consider the impact that growth in customers, energy, and demand between rate cases will have on base rate revenues. Third, he testified that the Company's proposal shifts the risk of changes to property (ad valorem) tax paid between rate cases from PSO to the ratepayers, and offers nothing in return to the ratepayers for assuming this risk, such as a lower return on equity (Bohrmann Rate Design Resp. Test. at 15:14-21).

131. THE COMMISSION FURTHER FINDS that the DOD/FEA Witness, Mr. Blank, stated two concerns regarding the Company's proposed change to its TA Rider. First, this proposed adjustment mechanism is very different than the currently approved items in the TA rider. The TA rider is currently limited to taxes on gross revenue and the production, transmission, or sale of electric energy. In other words, these are gross receipts taxes and/or per-unit (kWh) taxes that do not vary with rate base and underlying cost of electric service. Second, Mr. Blank indicated that the Company's proposed change to its TA Rider would constitute single issue ratemaking (Blank Rate Design Resp. Test. at 9:11-11:9).

132. THE COMMISSION FURTHER FINDS that the PUD Witness, Mr. Walkup, expressed two concerns regarding the Company's proposed change to its TA Rider. First, Mr. Walkup stated that this regulatory treatment would result in single issue ratemaking if the incremental property ad valorem taxes paid is recovered from ratepayers as a rider and reviewed separately from the rate case in which multiple parties intervene. Second, this proposed regulatory treatment would reduce the Company's incentive to negotiate with the Oklahoma Tax Commission to reduce or minimize PSO's ad valorem taxes paid (Walkup Rate Design Resp. Test. at 18:8-13).

133. THE COMMISSION FURTHER FINDS that the rationale provided by the Attorney General's Office, the PUD, and DOD/FEA is persuasive. The Company's proposal to modify its TA Rider to include property (ad valorem) taxes is denied.

Federal Tax Legislation

134. THE COMMISSION FURTHER FINDS that rates are to be fair, just and reasonable. Okla. Const. art. 9, § 18; *Valliant Tel. Co. v. Corporation Commission*, 1982 OK 159, ¶¶ 7, 18, 656 P.2d 273, 275. Moreover, the Commission has a duty to safeguard the public's interest with regard to utility rates and to ensure that the rates charged by the utility are the lowest, reasonable rates. 17 O.S. § 152; *State v. Oklahoma Gas & Electric Co.*, 1975 OK 40, ¶ 20, 56 P.2d 887, 81. Moreover, ratemaking proceedings are legislative in nature, in which the Commission is granted broad discretion in arriving at a rate that is fair to both the utility and its ratepayers:

> Rate making proceedings are legislative and, since the establishment of a rate is not a matter of exact science or capable of precise mathematical calculations, <u>broad, general, equitable principles must govern in the establishment of a rate</u>.

Community Nat. Gas Co. v. Corp. Comm'n of Okl., 1938 OK 51, 76 P.2d 393, 394, syl. 3.

135. THE COMMISSION FURTHER FINDS that at the hearing on the merits, Commissioner Anthony asked OIEC witness Mark Garrett as well as PSO witness Randy Hamlett several questions related to pending federal tax reform. (11/6/17 Early P.M. Tr. at 40:21-41:16, 72:3-18.) This issue was not presented in pre-filed testimony, nor did parties have the benefit of crafting proposals around legislation that has actually been passed to become law.

136. THE COMMISSION FURTHER FINDS that under the evidence presented, there is the potential for the enactment of tax reform legislation that could have an effective date as early as January 1, 2018, and could result in a substantial effect upon the corporate income tax rate as well as accumulated deferred income taxes. PSO's ratepayers should not be required to pay the cost of tax liability that does not exist.

137. THE COMMISSION FURTHER FINDS that steps be taken to protect the interests of customers if tax legislation is passed while deferring ultimate regulatory action to a future proceeding.

138. THE COMMISSION FURTHER FINDS that PSO be required to record a regulatory liability equal to excess ADIT and reduced ongoing tax costs related to any federal tax reform. The adjustment and regulatory treatment of this regulatory liability could be resolved in a future proceeding. This treatment would protect customer interests while allowing PSO and other interested parties to discuss appropriate action.

Cost of Service

139. THE COMMISSION FURTHER FINDS that PSO conducted two cost of service studies, one for jurisdictional cost separation between PSO's wholesale and retail customers and one for assignment of costs to the retail classes, which is used to determine the costs that different classes of customers impose on the PSO system. (*See* Exhibit 24.)

140. THE COMMISSION FURTHER FINDS that in its retail cost of service study, PSO proposed to change its allocation of transmission costs for retail customers from a 4CP allocation to a 12CP allocation. (Exhibit 24, pp. 13-14.)

141. THE COMMISSION FURTHER FINDS that OIEC recommends PSO's class cost of service study be modified to retain the four Coincident Peak (4 CP) methodology for allocation of transmission costs to PSO's retail customers, rather than changing to a 12 Coincident Peak (12 CP) methodology. (Exhibit 124, pp. 4-9.) PUD also rejects PSO's proposed 12CP method for transmission cost allocation and notes that PSO made the same request in Cause PUD 201500208 with the Commission rejecting that requested change. (Exhibit 112, pp. 16-18.)

142. THE COMMISSION FURTHER FINDS that the data demonstrates and the Commission has determined that PSO is clearly a summer peaking system for retail load. (Exhibit 124, p. 5.) This is the reason that both PSO's production costs and its transmission costs have historically been allocated using a 4CP allocation methodology. (*Id.* at 6.)

143. THE COMMISSION FURTHER FINDS that PSO's proposed transmission cost allocation is rejected and, instead, approves PSO's continued use of the 4CP allocation methodology for transmission costs.

Revenue Distribution

144. THE COMMISSION FURTHER FINDS that revenue distribution is the rate design mechanism by which the proposed change in revenue requirement is assigned to the customer classes. For this case, PSO's revenue distribution proposal follows the revenue distribution recommendation from the final order in PSO's most recent rate case, Cause No. PUD 201500208, to assign the total revenue requirement change to the retail rate classes. PSO proposes to move its major retail rate classes to its required cost to serve.

145. THE COMMISSION FURTHER FINDS and adopts PSO's recommended revenue distribution and finds that establishing rates based on the utility's cost of service produces equitable rates that reflect cost causation, send proper price signals and minimize price distortions.

Respectfully submitted,

Mary Candler

MARY CANDLER
Administrative Law Judge

12/11/17
Date

C:
Commissioner Murphy
Commissioner Hiett
Commissioner Anthony
Teryl Williams
Nicole King
Joseph Briley
Maribeth D. Snapp
James Myles
Elizabeth A.P. Cates
Matt Mullins

ATTACHMENT "A"

TESTIMONY SUMMARIES

DIRECT TESTIMONY

Public Service Company

MICHAEL J. VILBERT

Michael J. Vilbert, Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm testified on behalf of PSO.

Dr. Vilbert testified that to estimate the Company's cost of capital, he analyzed a sample of electric utilities identified as being in the same line of business as PSO, specifically the regulated electric utility business. He estimated the ROE for each sample company using both the discounted cash flow ("DCF") and the risk positioning approaches. The risk positioning approach consists of analyses based upon the Capital Asset Pricing Model ("CAPM") and the Empirical CAPM ("ECAPM"). He also provided estimates based upon the risk premium approach. The ROE estimates from both models are then adjusted for differences in financial risk among the sample companies as well as for PSO.

Dr. Vilbert testified that the result of this process is a sample average cost of equity as if the sample's average market-value capital structure had been one with a 48.5 percent equity ratio, which is the equity ratio PSO has proposed in this proceeding. This procedure results in an ROE that is consistent with both the financial risk inherent in the Company's proposed capital structure and the market-determined information on the sample's average overall cost of capital. Dr. Vilbert's Appendix B provides more discussion on the technical details of the ROE estimation models and procedure.

According to Dr. Vilbert, the sample ROE estimates range from a low of 9.1 percent to a high of 10.9 percent, but he believed that the estimates at the lower end of the range are not reliable because they do not consider the effect of the ongoing uncertainty in the financial markets and the downward pressure on the risk-free interest rate. Conversely, the estimates at the upper end of the range reflect the adjustment for the ongoing uncertainty in the capital market and are more reliable. Therefore, for an electric utility company of average business risk and with an equity ratio of approximately 48.5 percent, the best estimate of the range for the cost of equity is from 9¾ percent to 10¼ percent. To be conservative, he set the top of the range at 10¼ percent, but for higher risk companies, the top of the range could be as high as 10¾ percent.

Dr. Vilbert recommends that the Company be allowed an ROE of 10 percent on the equity-financed portion of its rate base. This is at the midpoint of the range of 9¾ percent to 10¼ percent that he believes is reasonable for electric utilities of PSO's financial and business risk.

Dr. Vilbert further testified that during times of economic uncertainty such as now, maintaining a strong credit rating is important to ensure access to capital markets at a reasonable cost. Credit rating agencies focus on cash flow, so regulatory policies that permit a regulated utility to recover its costs in a timely manner strengthen the utility's credit metrics. Conversely, regulatory decisions denying a regulated company full recovery of its costs or unduly delaying recovery weaken the credit metrics. Other regulators—including but not limited to those in Indiana, Colorado, Kentucky, Oregon, Alabama, and West Virginia—have recognized the importance of providing fair recovery mechanisms for electric utilities' stranded costs.

According to Dr. Vilbert, the development of credit ratings and generic financial strength is important because debt investors, as well as equity investors, are concerned about the financial strength of companies such as PSO. As a result of the 2008-2009 financial crisis, creditors have become increasingly concerned about anything that adversely affects cash flow or increases leverage. For a regulated entity such as PSO, financial strength is highly dependent upon the regulatory policy to which it is subjected. Because credit rating agencies focus on cash flow, they follow developments that affect PSO's cash flow such as determinations to reduce or disallow operations and maintenance ("O&M") or depreciation expenses. Multiple reductions or disallowances can have a major effect on the utility's ability to earn its allowed ROE even though individually each reduction may be small, because cumulatively they all reduce the earned ROE.

To a large degree, a utility's cash flow is determined by the approved revenue requirement, the magnitude of its capital expenditure program, and its real ability to earn the allowed ROE. Dr. Vilbert discussed PSO's recent financial metrics, its capital expenditure program, and the effect of any reduction in cash flow on the Company's financial metrics.

According to Dr. Vilbert, the electric industry is highly capital intensive, which means that regulated electric utilities must regularly access capital markets to acquire the funds necessary to purchase the assets needed to provide reliable service. Because PSO has a large capital expenditure program and must continue to provide reliable service, it is vital that the credit-supportive environment is maintained so that the Company can maintain its investment-grade credit rating. To meet these requirements, PSO requires a reasonable ROE as well as a fair opportunity to earn its allowed return.

Dr. Vilbert further testified that the cost of capital is higher than a mechanical implementation of the ROE estimation models may suggest. Although economic conditions have improved since the start of the crisis in about mid-2008, uncertainty remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. Worries about the low interest rate outlook in Europe and Japan as well as the United Kingdom's exit from the European Union have added to the concern. In addition, long-term government bond yields, which had dropped dramatically after the 2008-2009 credit crisis to unusually low levels, remain depressed relative to both historical levels and forecasts of future interest rates.

As a result, bond yield spreads remain higher than before the credit crisis, both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. Although the capital market indices have returned to or exceeded their pre-crisis levels, the recovery remains fragile in part because of the weakness and uncertainty in much of the rest of the world.

This uncertainty in the financial markets also affects the results of the estimation models, because both the risk positioning model and the DCF model are based upon the assumption that economic conditions are stable. That assumption is not currently met, so estimating the cost of capital under current conditions is more complicated than it would normally be.

Dr. Vilbert stated that because the uncertainty in financial markets affects the cost of capital for all companies, including regulated utilities such as PSO, he modified the parameters of the risk positioning model to recognize the effect of the increased volatility in the capital markets as well as the overall decline in long-term risk-free interest rates on the cost of capital. Specifically, he analyzed scenarios using two different estimates of the market risk premium ("MRP") and risk-free interest rate for use in the risk positioning model. These scenarios are discussed in more detail below. Further, given the current economic uncertainty and the downward bias it creates in the CAPM model results, he also placed substantial weight on the results of the DCF analyses in determining the range of reasonableness for the ROE.

Dr. Vilbert testified that Fitch, Moody's, and S&P agree that a key factor for PSO's credit rating is maintaining solid credit metrics with an emphasis on cash flow. Specifically, S&P notes that PSO has significant financial risk and pressures on the Company's stand-alone cash flow metrics are more in line with BBB ratings, though the relationship with its parent company, American Electric Power Company, improves the final credit opinion. All three rating agencies note that PSO has a relatively large capital expenditure program, and therefore the management of the program and recovery of its costs are important. The agencies identify the regulatory environment as an important element in determining PSO's credit rating.

Dr. Vilbert testified that the Company has not been able to earn its allowed ROE. Since 2014, PSO's achieved ROE has been over 100 basis points below its allowed ROE, as shown in **Error! Reference source not found.** below. S&P also noted this pattern that "earned returns continue to lag authorized levels."

Table 1
Achieved Return on Equity

Year	Allowed ROE	Actual ROE	Weather-Normalized ROE
2016	9.50%	8.54%	8.01%
2015	9.85%	8.62%	8.56%
2014	10.15%	8.86%	8.76%
2013	10.15%	10.73%	10.49%
2012	10.15%	12.76%	11.61%

According to Dr. Vilbert, similar to regulatory lag, when a regulator determines that some of the utility's costs should not be included in the rate base or the revenue requirement, they deny the utility the opportunity to earn a return on those costs and further harm the financial health of the company. A regulated utility should have the fair opportunity to earn its allowed return on its prudently incurred costs.

Regarding the Northeastern 4 generating plant, Dr. Vilbert testified that the Company chose to discontinue operation of the coal-fired Northeastern 4 generating plant, originally built in 1980, mainly for two unforeseen reasons. First, the significant decline in the price for natural gas over the past decade has greatly decreased the operating costs of gas-fired generation. Second, more stringent environmental regulations enacted over the past five years have increased the costs of operating coal-fired generating units.

It was Dr. Vilbert's opinion that the Company be allowed to earn a return on this investment because the investment was proved useful and beneficial to the utility's customers when it was proposed. The asset was developed prudently and included in the rate base. The reasons for its early retirement were due to environmental regulations and economic conditions outside of the utility's control.

Dr. Vilbert gave examples of what other regulators had done in a similar situation. According to Dr. Vilbert, other regulators have recognized the importance of providing fair recovery mechanisms for electric utilities' stranded costs. Here are some examples of how other jurisdictions in final orders have treated similar issues are as follows:

Indiana Michigan Power Company ("I&M")—In both Michigan and Indiana, I&M is to recover the net book value of the Tanners Creek Plant at its June 1, 2015 retirement date over the remaining 30-year useful life of I&M's Rockport Unit 1 Plant.

Kentucky Power Company—In Kentucky, Kentucky Power is to recover the coal-related retirement costs of the Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs through a rider over a 25-year period. The retirement costs include the remaining book values.

Appalachian Power Company ("APCO") and Wheeling Power Company ("Wheeling")—In West Virginia, APCO and Wheeling are to recover net book values of Kanawha River, Sporn, Glen Lyn, Clinch River 3, and coal-related investments in Clinch River 1 and 2 through 2040.

Public Service of Colorado ("PSC")—In Colorado, PSC is to recover the costs of 551 MW of retiring coal-fired electric generation and removal costs through depreciation during the period 2011 to 2017.

Portland General Electric ("PGE")—In Oregon, PGE is to recover, through changes to its depreciation rates, the costs, including decommissioning, of the early closure of its Boardman Coal Plant, changing the date of recovery from 2040 to 2020.

Alabama Power Company ("APC")—In Alabama, APC is to recover future unit retirements caused by environmental regulations, including unrecovered plant assets balances and costs associated with site removal and closure. Recovery

> is to occur over the remaining useful lives, as established prior to the decision for retirement.

In each of these cases, the companies are permitted a full rate of return on the remaining book value during the period over which the costs are to be recovered.

Some of the most relevant examples relate to the retirement of generating stations in Nevada. In 2014, the Public Utilities Commission of Nevada decided that Nevada Power Company would be allowed to recover the costs on the $247 million net book value of the 812 MW of retiring coal-fired power stations. Similar considerations have been made for Sierra Pacific Power Company in Nevada, Pacific Gas and Electric Company in California, and Black Hills in Colorado.

Dr. Vilbert testified that the ROE allowed by the Commission does not compensate the Company for risks of stranded costs. The Company made the investment with the expectation that it would be able to recover the full costs and earn a return. Disallowing recovery on the Northeastern 4 generating unit would harm the immediate financial health of the Company. Lengthening the depreciation schedule over which the remaining asset cost is recovered would also negatively impact the Company's cash flow and financial position. Furthermore, disallowing recovery on prudent investment would indicate decreased support in the regulatory environment for similarly situated utilities in Oklahoma under the OCC jurisdiction.

BRIAN J. FRANTZ

Mr. Brian J. Frantz, Manager, Regulated Accounting, of American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power, Inc. (AEP), testified on behalf of PSO.

Mr. Frantz testified that the PSO cost of service amount presented in this filing includes $63,288,003 of affiliate costs, which represents 18.5 percent of the total operations and maintenance (O&M) requested in this case. AEPSC accounts for $61,521,029 of these costs and $1,766,974 represents the amount PSO was billed from other affiliates. The AEPSC costs have been adjusted to develop a normal, ongoing level of costs billed to PSO, and as a result the affiliate costs are comparable (increased by 1 percent) to the costs included in Cause No. PUD 201500208, PSO's last rate case.

According to Mr. Frantz, AEPSC is a wholly-owned subsidiary of AEP and is the centralized service company providing, at cost, various professional support services for PSO and the other AEP affiliates. Using the service company to provide these support services allows the operating companies to concentrate their efforts on serving the immediate needs of their customers, while common processes can be performed in a centralized manner to promote efficiency and cost savings. The primary service company centers are located in Columbus, Ohio; Canton, Ohio; and Tulsa, Oklahoma. These three locations employ approximately half of the AEPSC employees, including approximately 600 in the state of Oklahoma.

Mr. Frantz further testified that AEPSC uses both benchmarking and outsourcing studies where available to review the cost of the products and services that are provided to affiliates, including PSO. AEPSC also employs many levels of oversight to ensure that its costs are billed accurately. This management oversight and controls includes, but is not limited to, internal AEPSC budget and actual cost reviews; and monthly review of the AEPSC bill by the affiliate companies.

Mr. Frantz testified that AEPSC is subject to numerous audit and reporting requirements, both as a member of the AEP Corporation for financial reporting, and as a requirement of federal and state jurisdictions. These requirements include:

- Annual AEP independent audit by Price Waterhouse Coopers (Deloitte & Touche prior to the 2017 calendar year audit);
- Audit required under the 16 Tex. Admin. Code (TAC) § 25.272, "Code of Conduct for Electric Utilities and Their Affiliates," filed every three years, showing compliance with the Texas affiliate code of conduct;
- Annual "Report of Affiliate Activities" filed with the Public Utility Commission of Texas;
- Annual Affiliate Activities report filed with the Virginia State Corporation Commission;
- FERC Form 60 which is the annual report of AEPSC financials and allocations;
- Maintenance of an AEPSC Cost Allocation Manual, which documents AEPSC's cost allocation methodologies and accounting procedures and which is required by the states of Kentucky, Ohio, Oklahoma and Arkansas; and
- Periodic audits of AEPSC accounting and billing procedures conducted by FERC staff.

According to Mr. Frantz, with FERC Order No. 667, issued December 9, 2005, FERC amended its regulations to implement the repeal of the Public Utility Holding Company Act of 1935 and adopted rules to implement the Public Utility Holding Company Act (PUHCA) of 2005. FERC continues its authority under the Federal Power Act (FPA) and states in Order No. 667 that its rate authorities and information access under the FPA "...enable the Commission to detect and disallow from jurisdictional rates any imprudently-incurred, unjust or unreasonable, or unduly discriminatory or preferential costs resulting from affiliate transactions between companies in the same holding company system." As to the use of approved Allocation Factors, FERC stated that it will "...rely on our ratemaking authority to examine these agreements or require them to be filed on an as-needed basis to determine whether the regulated utility's purchase of non-power goods and services were prudently incurred and just and reasonable." Through its rules, FERC has determined that it will not require entities that were using the SEC's "at-cost" standard for traditional centralized service companies, such as AEPSC, to switch to a "market" standard.

FERC Order No. 684, issued October 19, 2006, discusses financial accounting, reporting, and records retention requirements under the Public Utility Holding Company Act of 2005.

Mr. Frantz further testified that in that order, FERC issued a new Uniform System of Accounts (US of A) for centralized service companies, added preservation of records requirements for holding companies and centralized service companies, revised FERC Form No. 60, Annual Report of Centralized Service Companies, to provide for financial reporting consistent with the new US of A and provided for electronic filing of the revised FERC Form No. 60. The requirements of FERC Order 684 became effective January 1, 2008.

FERC states in Order 684's summary that "the final rule will provide for greater accounting transparency for centralized service company operations, and uniform records retention by holding companies and service companies subject to PUHCA 2005. This transparency will protect ratepayers from pass-through of improper service company costs."

Mr. Frantz testified that AEPSC'S billing processes did not change with the adoption of FERC Order 684.

The requirements of FERC Order 684 were already being met by AEPSC and are consistent with the SEC's previous requirements. The current processes for accumulating and billing at cost to affiliates, like PSO, are operating effectively and efficiently, and changes have not been required. Changes required by the new Service Corporation US of A were minor.

According to Mr. Frantz, on an annual basis, FERC requires the filing of FERC Form No. 60, "Annual Report of Centralized Service Companies." In addition, FERC completed an audit of AEP affiliate transactions in 2010. The primary focus of this audit was AEPSC billing and allocation processes, as well as compliance with the FERC chart of accounts and record retention requirements.

Mr. Frantz testified that benchmarking is a common method that companies use to determine how the services they provide compare with companies that provide similar services. These comparisons can relate to the cost of services provided, the efficiency of services provided, customer satisfaction, or other metrics that may be comparable between companies. The results of benchmarking studies can, in some cases, help to confirm the efficiency of the service provided. In other cases, benchmarking results can reveal that a service is provided at a lower cost by other peer companies in the study. When this occurs, benchmarking studies are especially useful in that they provide insight to best practices that can be evaluated and implemented to lower the cost of providing a service. Market comparison studies are reviews undertaken to determine whether a service could be provided at a lower cost or more efficiently by an outside company.

Mr. Frantz testified that AEPSC reviews its costs in comparison to market or third-party data.

Where information is available and it is practical to do so, AEPSC reviews, performs, or participates in benchmarking studies, cost studies, and market comparisons. Each of the AEPSC organizations discussed earlier in my testimony participates in or conducts various benchmarking or market comparison studies, as needed, to evaluate key aspects of their operations. For example, the Information Technology department may choose to focus studies on the efficiency of servers and personal computers, which comprise a large amount of their total costs. The Supply Chain department may choose to focus studies on materials management and other purchasing metrics, as these studies would correlate to their primary cost drivers. The AEPSC call centers may choose to focus studies on customer satisfaction, a critical element in their operations. Human Resources, on the other hand, may participate in studies to examine their own operations, such as benefits processing, as well as participating in broader studies to examine the appropriate pay levels for all AEP employees. In all cases, the use of benchmarking and market comparison data allows each department to gain insights into the overall efficiency of the services being provided to affiliates, including PSO. AEPSC departments also periodically review processes and procedures to look for better ways to provide service and ensure that tasks are performed efficiently for the benefit of the utility companies.

According to Mr. Frantz, approximately 66 percent of AEPSC's charges to PSO are based on employee payroll-related costs. AEP and its operating companies provide compensation to their employees that approximate median wage levels for the electric utility industry. This practice allows PSO and AEPSC to attract, retain and motivate qualified employees while not being a wage leader within the electric utility industry. The compensation section of the Human Resources department develops and maintains compensation programs for PSO and AEPSC that are market competitive, and they also conduct ongoing research and recommend changes to compensation programs as necessary. By diligently reviewing the compensation levels for both AEPSC and PSO employees, the company ensures that this significant percentage of the overall cost of the services it provides is reasonable and market competitive. The costs incurred by AEPSC and billed to PSO are necessary for PSO's operations and benefit its customers by enabling PSO to meet service obligations in an efficient, cost-effective manner.

RANDALL W. HAMLETT

Mr. Randall W. Hamlett, Director of Regulatory Accounting Services for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf o PSO.

Mr. Hamlett testified that the application Package (AP) Schedule B-01 shows a revenue deficiency of $169,667,526 on a total company pro-forma basis. According to Mr. Hamlett, the following table summarizes the results presented in PSO's AP.

Description	Schedule Reference	Total Company Pro-Forma
Rate Base	B-02	$2,527,472,526
Rate of Return	F-01	7.22%
Operating Income Requirement		$182,483,516
Pro-Forma Operating Income	B-02	$78,943,783
Operating Income Deficiency		$103,539,733
Revenue Conversion Factor		1.638671
Revenue Deficiency		$169,667,526

The Company's Oklahoma jurisdictional pro-forma rate base at December 31, 2016, is $2,526,476,472 (AP Schedule B-02, line 21, col. 7). The Oklahoma jurisdictional pro-forma operating income is $78,966,486 (AP Schedule B-02, line 22, col. 7). The resulting Oklahoma jurisdictional return earned on rate base for the adjusted test year ending December 31, 2016, is 3.13% (AP Schedule B-02, line 23, col. 7).

Mr. Hamlett testified how the company accounts for O&M storm costs. Order 564437 issued in Cause No. PUD 200800144 allows PSO to defer, as a regulatory asset or liability, the difference in actual distribution storm expense from the $2.87 million included in PSO's base rates. Final Order 581748 issued in Cause No. PUD 201000050 did not alter this accounting. Final Order 639314 issued in Cause No. PUD 201300217 did not alter this cost recovery mechanism and allowed for recovery of an estimated $18.5 million related to three significant storms that occurred in 2013. Final Order 657887 and Order 658529 Modifying Order No. 657877 issued in Cause No. PUD 201500208 did not modify the cost recovery mechanism, and continued to provide recovery of the $18.5 million including inclusion of the regulatory asset in rate base.

Mr. Hamlett testified that the Company has significantly under-recovered significant storm O&M expenses. Regarding the $18.5 million of storm expenses from previous Cause Numbers, PSO will still have $6,166,655 of unrecovered storm O&M expenses at the end of December 2017, the anticipated date of new base rates. In addition, PSO had six storms from January 2015 through January 2017 where restoration efforts' cost exceeded $1 million per storm. The sum of those restoration effort total $33,143,311 of O&M expenses through April 2017. Smaller ongoing storms are slightly over-recovered as of the end of April 2017, by approximately $350 thousand.

Mr. Hamlett testified that PSO was requesting that the two amounts be added together and amortized over four years, the same time period granted for the $18.5 million amount in Cause No. PUD 201300217. PSO was also requesting that the June 30, 2018, unamortized balance be included in rate base similar to Cause No. PUD 201500208. The amount requested to be included in cost of service is $9,827,492, which is an increase of $5,202,492 over the $4,625,000 amount included in the test year. The amount included in rate base is $3,854,154 for the remaining amount of the previously-granted $18.5 million and $29,000,397 for the new significant storms.

Mr. Hamlett further testified that PSO was requesting changes regarding O&M storm recovery that was approved in Cause No. PUD 200800144 and continued in Cause Nos. PUD 201000050, PUD 201300217 and PUD 201500208.

Over the past seven years, PSO has incurred large amounts of O&M related to various storms. The annual restoration efforts' costs have varied from a low of approximately $1 million to a high of almost $25 million. The result of this is that in two of the last three base rate cases, PSO has requested amortization recovery of past significant O&M storm costs be included in future rates. In the one case that PSO did not request additional recovery, recovery of approved past significant storms was included in cost of service. PSO believes it would be better to include an amount that includes these significant storms and allow a more concurrent recovery versus an after the fact recovery, thus matching storm costs with current customers. A seven year average of storm O&M costs is approximately $10.5 million for distribution and $700 thousand for transmission. The test year amounts for distribution was $2.87 million while transmission was $66 thousand. Thus, PSO is requesting an increase in base rates of $8.264 million to reach the average level of $11.2 million of storm O&M expenses in base rates. As in the past, any storm-related costs above or below the amount included in base rates, now requested to be $11.2 million, would be deferred as a regulatory asset or liability. Any regulatory asset or liability balance would be addressed in an appropriate future filing at the OCC. The Final Order in this proceeding should contain a finding that PSO's O&M storm costs in base rates is $11.2 million and actual incurred amounts above or below that level will be deferred into a regulatory asset or regulatory liability.

Mr. Hamlett further testified that the current practice approved by the OCC is to include an estimate of rate case expenses, amortized over an applicable time period, to be included in the base rate revenue requirement. In addition, the Commission has historically allowed PSO to defer as a regulatory asset or liability the difference in actual expenses when compared to the amount included in base rates and address the difference in PSO's next base rate filing. Any difference between the estimated amounts for this proceeding, including the independent evaluator from Cause No. PUD 201600300, would be deferred as a regulatory asset or regulatory liability.

Mr. Hamlett testified that in Order No. 657877, the Commission stated:

> The Commission finds that cost recovery should be approved through base rates for plant investment in service as of July 31, 2015, attributable to PSO's environmental compliance plan ("ECP"). The Commission finds that those plant investments not in service as of July 31, 2015, relating to PSO's Northeastern Unit 3 DCI/ACI/FF investment and PSO's Comanche Dry Low NOx Burners investments should receive deferred accounting treatment for depreciation, property tax and a weighted average cost of capital return on such investment once the investments are placed in service. The Commission finds that the deferred accounting regulatory asset resulting from reasonable investments shall be included in rate base in PSO's next base rate proceeding. The Commission finds that PSO should be denied cost recovery for the accelerated depreciation that PSO seeks to recover for Northeastern Units 3 and 4 over the 2016 to 2026 period and that, to mitigate rate increases, depreciation for the undepreciated, "original" costs of these two units should continue on its current pace to 2040. The Commission finds that PSO should be granted cost recovery in this proceeding for PSO's SOFA investments on Northeastern Units 3 and 4, Southwestern Unit 3, and the majority of its investments in Northeastern Unit 2 to the extent that such investments are in service as of July 31, 2015 [At page 5.]

Mr. Hamlett stated that the amount of the ECP deferrals is dependent upon the date new base rates are implemented in this proceeding. Assuming new base rates are implemented on the first billing cycle of January 2018, the ECP deferrals will total $44,559,693 as summarized in the table below.

Description	Amount
Return	$30,257,348
Depreciation	7,818,453
Property Taxes	4,237,631
Carrying Cost on Regulatory Asset	2,246,260
Total	$44,559,693

According to Mr. Hamlett, PSO is proposing to recover the deferral over the same time period that the Northeastern coal investment will be recovered. That time period is through 2040. Thus, the time period for the ECP deferral recoveries would be 2018 through 2040 or 23 years. The June 30, 2017, balance has been included in rate base in compliance with the Commission's finding in Order No. 657877.

Mr. Hamlett testified that to be in compliance with the ECP, PSO retired Northeastern Unit 4 in April 2016 utilizing standard FERC Uniform System of Accounts retirement entries. These entries debit (decreased) accumulated depreciation and credited (decreased) plant in service for the original cost of the investment. The effect of such entries is that any under-depreciated assets value of a retired investment, whether it be a pole or a power plant, resides in accumulated depreciation to be utilized in a future depreciation study that will adjust depreciation rates on a prospective basis that recognizes the remaining net amount to be depreciated in the future.

PSO is proposing to recover the remaining investments in Northeastern units 3 and 4, including the ECP investments on Unit 3, through 2040, the same date from the Commission's Order in Cause No. PUD 201500208. The depreciation rates to be applied to the Northeastern Unit 3 gross plant investment, that were calculated by PSO witness John Spanos, are designed to recover the remaining Northeastern units 3 and 4 remaining net plant through 2040.

Mr. Hamlett testified that the recovery period will require the use of regulatory asset accounting.

Since Northeastern Unit 3 is scheduled to be retired in 2026, its investment will not be fully recovered at the time it is retired. Thus, regulatory asset accounting will be required in accordance with ASC 980-340 Regulated Operations-Other Assets and Deferred Costs. Under this standard, incurred costs may be capitalized as a regulatory asset. In this case, the incurred costs would be depreciation through the retirement date of 2026 while recovery would be through 2040.

According to Mr. Hamlett, the regulatory asset should be included in rate base, just as the ECP deferrals are, and likewise should be amortized through 2040 as applicable.

Mr. Hamlett testified regarding the AMI Rider Tariff. The commission stated at page 8 of Order No. 657877: "The Commission rejects the ALJ's recommendations regarding the AMI rider and finds that the rider shall remain in effect until the first base rate case subsequent to the full implementation of AMI, consistent with the current provisions of the AMI rider tariff." Thus, the AMI rider continued and will continue until PSO's first base rate case subsequent to full implementation. Full implementation has occurred making this the subsequent first base rate case.

According to Mr. Hamlett, in the previous base rate case, PSO removed the AMI investment and expenses from base rates via pro-forma adjustments. In this case, no adjustments were made to remove the AMI investment or remove all AMI-related expenses. However, the test year was a combination of pre- and post-AMI full implementation. Thus, certain legacy system expenses were removed because they are non-recurring and certain expenses were added via pro-forma adjustments to normalize the test year expenses to an ongoing post-deployment level.

Mr. Hamlett testified that the savings related to AMI were incorporated into the test year.

Regarding the old meters that were retired due to AMI, PSO established a regulatory asset for the unrecovered net book value of the non-AMI meters in accordance with the Commission Order No. 639314 issued in Cause No. PUD 201300217. PSO has been amortizing the regulatory asset using a 9.58% depreciation rate as detailed in the Order. Finally, the net regulatory asset has been included in rate base consistent with the Order.

Mr. Hamlett testified that PSO tracked the revenues and costs on a monthly difference using over/under accounting with the difference between the revenues and costs we deferred into a regulatory asset or liability depending on the outcome of the calculations (revenues greater than costs – regulatory liability, costs greater than revenues – regulatory asset). At December 31, 2016, PSO had returned approximately $5.1 million in savings to customers through the AMI Rider with an additional $6 million scheduled to occur in 2017. Therefore, the $11 million of guaranteed AMI savings contained in Cause No. PUD 201300217 Joint Stipulation and Settlement Agreement approved in Order No. 639314, will have been returned to customers by the time new rates are implemented in this proceeding.

The over/under accounting will end when the AMI rider is discontinued and the AMI costs are included in base rates (i.e., the implementation of new rates and tariffs resulting from this case). The AMI tariff rate was recently revised with a goal of a minimal remaining balance at the end of 2017. Mr. Hamlett recommended that PSO provide the OCC staff with the final balance within 60 days of the date the AMI rider is discontinued and that the balance be transferred to the fuel over/under balance.

Mr. Hamlett further testified that PSO is requesting that the Final Order in this case recognize the amount of $35,779,771 in property (ad valorem) tax approved to be recovered through base rates in this case. PSO requests that the Tax Adjustment Rider (TA) be modified to include a property (ad valorem tax) adjustment factor that will be adjusted annually to account for an incremental amount of property (ad valorem) taxes expensed above or below the baseline amount included in base rates. PSO has modified the currently-approved TA to accommodate this proposal. The annual true-up is proposed to be the difference between the actual property (ad valorem) taxes recorded on PSO's books and records and the actual amount being recovered from revenues billed to customers. That difference is then refunded or surcharged to customers in a subsequent year.

According to Mr. Hamlett, PSO will defer, as a regulatory asset or liability, the difference in actual property (ad valorem) taxes and the amount being recovered from customers on a monthly basis. The sum of the monthly differences will become the true-up amount to be refunded or surcharged.

Mr. Hamlett testified that to serve its customers, PSO has significant investments that generate a large amount of property (ad valorem) taxes. PSO must pay the applicable taxing authorities for which the amount it pays is outside the direct control of the Company. By including property (ad valorem) taxes in the TA, PSO's customers will ultimately pay exactly what PSO pays not a penny more or a penny less. If this accounting is not adopted, the amount paid by customers will be different than the amount paid by PSO.

Mr. Hamlett testified that the adjustments made by PSO to the test year financial results are for known and measurable items included in its revenue requirement to reflect a normal, ongoing level of operations. Examples of the adjustments include the following:

- Normalization adjustments to adjust the test year data to normal ongoing levels of revenue or expense. An example of this type of adjustment is the adjustment related to pension costs to reflect the ongoing level based on the current actuarial study.

- Adjustments to book amounts to a cost of service ratemaking basis for the purpose of including items recovered in rates or eliminating items not recovered in base rates. Examples of this type of adjustment are the inclusion of interest expense to be paid on customer deposits in PSO's cost of service, which are not included in operating income on a financial reporting basis, and the removal of both the revenues received and expenses incurred in PSO's energy efficiency program. These energy efficiency program expenses and revenues are reported in operating income on a financial basis, but excluded from PSO's cost of service since they are subject to a separately-approved OCC rider and are not recovered in base rates.

- Annualization adjustments to reflect ongoing levels of revenue, expense, or capital. Examples of this type of adjustment include annualizing depreciation expense to reflect the annual effect of the depreciation rates recommended by PSO in this filing, and including in plant in service the investment incurred by PSO for projects that are currently in service or expected to be in service by June 30, 2017.

Mr. Hamlett described the components included in PSO's rate base. The rate base components included on AP Schedule B-02, column 3, represent the test year unadjusted amounts for the following: Plant in Service, Construction Work In Progress, Plant Held for Future Use, Accumulated Depreciation, Cash Working Capital, Prepayments, Materials and Supplies, Fuel Inventories, Customer Deposits, Off-System Trading Deposits, Accumulated Deferred Income Taxes, Excess Deferred Taxes and pre-1971 Investment Tax Credits. The rate base schedule starts with the actual balances at December 31, 2016, with some amounts restated to reflect a thirteen-month average balance for the period of December 2015 through

December 2016. PSO determined the Cash Working Capital component on AP Schedule B-02, line 9, using a lead-lag study.

Mr. Hamlett testified that AP Schedule E-01 presents a Cash Working Capital ("CWC") allowance of a negative $110,725,044, which reduces PSO's rate base and resulting revenue requirement. CWC is an estimate of the funds supplied by investors to cover PSO's operating costs during the period before revenues are collected from customers. The allowance is quantified using a lead-lag study and recognizes that investors are entitled to earn a return on the funds they supplied to finance the day-to-day operations of the business. In this case, as in past PSO cases, the negative CWC allowance is the result of PSO minimizing the delay in collecting revenues from customers through the factoring of accounts receivable. PSO has included factoring expenses in cost of service as permitted in prior Commission orders as an offset to this negative CWC allowance.

Mr. Hamlett testified regarding the prepaid pension balance. According to Mr. Hamlett, the Prepaid Pension amount is entirely supported by actual cash contributions in excess of pension cost. Inclusion in rate base will allow recognition of the Company's cost of funds on these cash contributions. Not included in the Company's request are non-cash accrual adjustments made under ASC 715-20 (formerly FAS158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*), since such adjustments have no effect on the amount of the Company's cash pension investment or its ASC 715-30 pension cost.

These additional contributions were made to address substantial underfunding that would have continued to exist if the contributions had not been made. They do not relate to anticipating or pre-funding future obligations, but rather were made to catch up funding to the current accumulated benefit obligation. Even with these additional contributions, the Company's qualified pension plan was only 99.7 percent funded in terms of the ASC 715-30 benefit obligation at December 31, 2016. The additional pension contributions have been prudently incurred by the Company to provide service to its customers, are necessary for the provision of service, and constitute property that is used and useful in providing public utility service.

Pension cost is established by generally accepted accounting principles as set forth by the FASB. However, pension contributions are based on separate Employee Retirement Income Security Act (ERISA) requirements, so the amount of pension cost and the amount of pension cash contribution most often vary. Generally accepted accounting principles require that this difference be recorded on the balance sheet as a prepayment if contributions exceed cost or as a liability if cost exceeds contributions.

Mr. Hamlett further testified that customers benefit from the investment earnings on the additional fund assets. This has the effect of reducing pension costs under generally accepted accounting principles in an amount that grows over time through compounding. The additional pension contributions recorded as a prepaid pension asset reduced by approximately $11.9 million on a total Company basis the 2016 pension cost that the Company would have had to reflect in rates. In other words, had the Company not made the additional pension contributions, the total amount of pension cost that PSO would have to reflect in rates would be approximately $18.3 million instead of $6.4 million.

Mr. Hamlett testified that the requested prepaid pension asset treatment was consistent with the final Order's revenue requirement calculation from PSO's most recent rate case Cause No. PUD 201500208.

Mr. Hamlett supported the following additions and deductions to rate base included in PSO's filing.

OTHER ADDITIONS AND DEDUCTIONS TO RATE BASE		
Adjustment	**Increase / (Decrease)**	**Reference**
Customer Deposits (Year End)	($49,674,708)	SP WP B-06
Off-System Trading Deposits	($63,582)	SP WP B-06
Red Rock Regulatory Asset	$9,050,820	SP WP B-03-3
Deferred Storm Expense – 201300217	$3,854,154	SP WP B-03-5
SFAS 106 Medicare Subsidy	$3,919,320	SP WP B-03-6
ECP Deferrals	$30,508,931	SP WP B-03-8
Retired Meters	$50,131,107	SP WP B-03-9
ARO Retired Plant	$539,767	SP WP B-03-10
Deferred Storm Expense	$29,000,397	SP WP B-03-11
IPP System Upgrade Credits	($1,050,066)	SP WP B-03-1
Refundable CIAC	($378,434)	SP WP B-03-4
Deferred Pole Attachment Revenue	($788,015)	SP WP B-03-7
Accumulated Deferred Income Taxes (ADIT)	($1,041,1979914)	AP B-02
Excess Deferred Income Taxes	($4,937,384)	SP WP J-03
Def. Investment Tax Credit	($15,971)	AP B-02

Mr. Hamlett testified that AP Schedule H-01 provides the components of PSO's operating income on a book basis, a total company pro-forma basis, and a pro-forma basis after the proposed revenue increase. This schedule contains operating revenues, operating expenses, operating income before taxes, income taxes, and net operating income. The schedule also shows rate base and rate of return on rate base. AP Schedule H-02 provides each individual adjustment to operating income by the categories listed on AP Schedule H-01. The SP workpapers (marked as SP WP H-02-1, SP WP H-02-2, etc.) also provide supporting information on each individual adjustment.

Mr. Hamlett testified that PSO has utilized a 2040 retirement date as ordered by the OCC in Order No. 657877 issued in Cause No. PUD 2015000208. As detailed earlier, this will require deferred expense / regulatory asset accounting to recognize the difference between the 2026 retirement date and the Commission's order, which utilizes a 2040 retirement date. Therefore, PSO requests that the final order in this proceeding recognize and authorize PSO to utilize regulatory asset accounting to recognize the difference between the 2026 retirement date and the 2040 date used to set rates.

The Northeastern Unit 4 retirement entries were in accordance with the FERC USofA. Under the FERC USofA, PSO records plant in service assets at original cost by various FERC accounts on its books. Over time, PSO depreciates the assets using approved depreciation rates, which are recorded in accumulated depreciation.

Plant in Service less Accumulated Depreciation is known as Net Plant in Service. When plant is retired, the Plant In Service account is reduced by the original cost and a corresponding entry is made to accumulated depreciation. The FERC USofA states:

> B (2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

According to Mr. Hamlett , for this retirement, PSO followed the FERC USofA and the book cost of Northeastern Unit 4 was credited to the appropriate electric plant account and the exact same book cost of Northeastern Unit 4 was charged to accumulated provision for depreciation (i.e., credit plant in service and debit accumulated provision for depreciation for the exact same amount).

The result is the Northeastern Unit 4 asset is no longer in plant in service. However, because Northeastern Unit 4 was not fully depreciated at the time of retirement, the amount of credits from applying approved commission depreciation rates was not large enough to cover the debit associated with the retirement entry.

This is common under FERC retirement accounting according to Mr. Hamlett. A company's assets are made up of many different assets in various FERC accounts and there are many reasons an asset is retired on a utility's books. For example, it may simply be worn out, and it is time to replace it. A new pole in service may be knocked over by an inattentive driver. A group of transmission towers may be retired due to a major ice storm, or a group of distribution poles may be retired because they are relocated as part of a major highway project. Or, as in this case, a group of assets at a power plant may be retired because the power plant will no longer generate electricity due to the cost of government regulations. Under the FERC USofA, all of these retirement entries are the same basic entry: debit Accumulated Depreciation and credit Plant in Service for the original cost. It does not matter if the individual assets are 75 years old or 2 days old. In other words, individual assets will have many different useful lives, which means that the useful life of such assets is not a known amount, but is an estimate. Over time, assets are retired and replaced, and in rate cases, depreciation rates, through a depreciation study, are adjusted and refined for what is the appropriate estimated useful life to include for this remaining group of assets. The Net Plant in Service amount is the amount that is included in rate base.

Mr. Hamlett testified that PSO requests that the Commission make the following findings of fact:

(1) PSO's total Oklahoma jurisdictional pro-forma adjusted rate base at December 31, 2016, is $2,526,476,472.

(2) PSO's Oklahoma jurisdictional pro-forma net operating income for the test year ending December 31, 2016, is $78,966,486.

(3) PSO's overall requested return on rate base is 7.22%.

(4) PSO's Oklahoma jurisdictional pro-forma base rate cost of service is $182,411,601.

SCOTT A. RITZ

Mr. Scott Ritz, Director of Customer Services & Marketing for Public Service Company of Oklahoma (PSO), testified on behalf of PSO.

Mr. Ritz testified that prior to PSO's AMI deployment, meters were manually read each month. Many conditions such as locked gates, aggressive dogs, inclement weather, and employee absences prevented timely and accurate readings from occurring. When these situations occurred, it was necessary to either request a special trip by a field agent to read the meter or to estimate the customer's monthly usage. This estimation process often created frustration for customers and complicated PSO's goal of ensuring consistently accurate billing statements. With automated meter reads, AMI nearly eliminates estimated bills, leading to greater billing accuracy, which also leads to improved customer satisfaction. For example, when a customer wishes to terminate service, the AMI meter is read remotely and a final bill is issued immediately.

According to Mr. Ritz, just prior to implementation of AMI, PSO estimated an average of 16,300 customer bills monthly, or approximately 195,000 annually. This represented approximately three percent of total bills sent to customers. During the deployment of AMI, the number of estimated meter readings declined to less than 370 estimated meter reads per month. As of 2017, the number of estimated reads continues to decline to approximately 100 per month, which represents 0.02 percent of all bills.

Mr. Ritz testified that prior to AMI, PSO had to manually disconnect and reconnect service at customers' premises. With the implementation of AMI, meters equipped with a remote service switch enable power to be turned on or off remotely. PSO has the ability to connect electric service remotely for the majority of customers, typically within minutes of a customer's request. Remote service connections help customers initiating or transferring service, requiring service connections on weekends or holidays, and/or needing quick reconnection after a service disconnect. For disconnections, service reconnections occur within minutes after payment remittance. Mr. Ritz testified this happens 24 hours a day, seven days a week—even on holidays.

Mr. Ritz further testified that call center representatives now have real-time access to meter data, which helps them immediately discuss actual usage information with customers. As an example, when a customer calls about a power outage, the real-time access allows call center representatives to determine whether the outage is due to a PSO outage or to an issue on the customer side of the meter. Before AMI, PSO sent an agent to the field to verify the outage and identify its origin. In today's ever-changing and fast-paced environment, AMI is able to deliver the types of immediate services that our customers have come to expect.

According to Mr. Ritz, prior to AMI, customers had to individually notify PSO of outage situations. Today, PSO is immediately aware of a customer's outage and can respond more rapidly and with more detail about the extent and cause of the outage. Through predictive analytics from AMI, PSO is also able to identify electrical system issues that could lead to a decreased level of power quality or even future outages for customers. This predictive information often enables PSO to make repairs or adjustments to the grid even before customers are aware a problem exists.

This reduction in potential power quality issues and outages improves the customer experience. In fact, J.D. Power and Associates reports that overall customer satisfaction increases as much as 45 points, or six percent higher, when a customer has "perfect power." Obviously, "perfect power" is an ideal state, but the ability to reduce potential power quality issues and outages certainly contributes to customers achieving that state.

Mr. Ritz also testified that with the implementation of AMI, PSO can communicate information with customers in ways that were previously unavailable. Customers now have access to the My Energy Advisor web portal, as well as the Mobile Alerts system that communicates customer-specific service and billing information.

Mr. Ritz testified that PSO is able to offer customers four new, money-saving rate plans: Direct Load Control (DLC), Time of Day (TOD), TOD + DLC Combo, and Variable Peak Pricing (VPP). Collectively, these programs are referred to as Power Hours. PSO is also able to offer Power Pay, a voluntary payment option that allows customers to pay as they go in lieu of the traditional post-pay billing. Power Hours and Power Pay, together referred to as "Consumer Programs".

According to Mr. Ritz, these programs will have a very positive affect on our customers' satisfaction. According to J.D. Power and Associates, customers place considerable value on the availability of optional rate plans with satisfaction increasing as much as 18 percent (or 113 points) when customers participate. Additionally, these offerings allow us to further engage with our customers, which drives satisfaction even higher. Awareness (as compared to unawareness) of available programs increases customer satisfaction as much as 10 percent.

Mr. Ritz testified that as discussed in Mr. Dohrmann's testimony, the programs are creating "...energy savings and demand reductions [that provide] a pathway to financial savings for program participants." ADM verified that customers enrolled in the TOD rates saved on average $26 during the peak season. For customers participating in DLC events, they received approximately $12 on average in bill credits during the summer of 2016.

While the 2016 results were positive, it is important to note that AMI was not fully deployed until July of 2016; therefore, the 2016 averages should not be viewed as the ceiling for potential customer savings. Participants in the TOD programs have the potential to save as much as 30 percent, while DLC participants can earn $40 in bill credits per thermostat. PSO is continually working to refine program methodologies and increase customer communications to assist Power Hours participants in maximizing savings.

Mr. Ritz stated that Power Pay is a voluntary payment option commonly referred to as prepay. This payment option allows customers to pay as they go in lieu of the traditional post-pay billing options.

The Commission approved the program in June 2016, and PSO tested the program with employees beginning in July 2016. After a successful testing period, PSO began offering the program to external customers in November 2016. In mid-February 2017, PSO started to formally market the program to customers through several channels, such as email campaigns, customer mailings, customer brochures, bill stuffers and videos. TV and radio advertisements were also conducted in May 2017.

PSO currently has approximately 1,500 Power Pay enrollments, with approximately 100 customers signing up per week.

According to Mr. Ritz, PSO developed a comprehensive communication and education plan to inform customers about AMI meters and how to maximize the benefits, specifically through participation in Power Hours. This plan employed several different means of communication such as (1) outreach at community events and customer meetings, (2) a tailored marketing campaign that included email and social media campaigns, and (3) radio and TV advertisements promoting the programs.

STEVEN F. BAKER

Mr. Steven F. Baker, Vice President of Distribution Operations for Public Service Company of Oklahoma (PSO or Company), testified on behalf of PSO.

Mr. Baker testified that PSO's Distribution Operations organization, which is comprised of three operating districts and three functional support departments, oversees the planning, construction, operation and maintenance of PSO's distribution system. By comprehensive and effective reliability planning, programs, and system investments, the Distribution Operations organization continues to provide 547,000 PSO customers with reliable electric system performance that compares favorably to state, regional, and national reliability averages.

PSO has invested approximately $205 million in its distribution system beyond the investment included in its last base rate proceeding (PUD 201500208). The investment supports safety, customer growth, customer satisfaction, reliability improvements, capacity planning, and engineering standards, in addition to complying with Commission rules. The distribution capital investment projects are necessary and reasonable to continue providing safe, reliable, and economic service to our customers.

PSO's adjusted test year distribution O&M expense is approximately $92.5 million, which includes an adjustment for a requested amount of severe storm amortization expense, as well as an adjustment to the annual storm cost amount. This adjusted test year expense is instrumental in supporting the Company's day-to-day distribution operations to ensure the reliable and safe delivery of power to customers.

Since PSO's last base rate case, PSO has experienced and prepared for several severe weather events, including ice, wind, and snow storms, which impacted PSO's distribution system. These events have cost nearly $30 million in O&M, for which PSO is seeking recovery in this proceeding. Additionally, the implementation of AMI throughout PSO's service territory has helped to shorten customer outage duration and reduce the overall cost of restoration efforts during these events.

Mr. Baker further testified that PSO serves approximately 547,000 customers in 232 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. This includes approximately 470,000 residential, 63,000 commercial, 6,200 industrial, and 7,800 other customers. PSO's Distribution Operations organization includes three districts: Tulsa, Lawton, and McAlester. PSO's distribution system includes approximately 15,200 overhead circuit miles and almost 4,900 underground circuit miles.

Mr. Baker discussed PSO's distribution reliability. Mr. Baker stated that PSO's SAIFI, SAIDI, and CAIDI indices excluding major events, as defined by the Oklahoma Reliability Rules, are shown in Figures 1, 2, and 3 respectively.

Figure 1

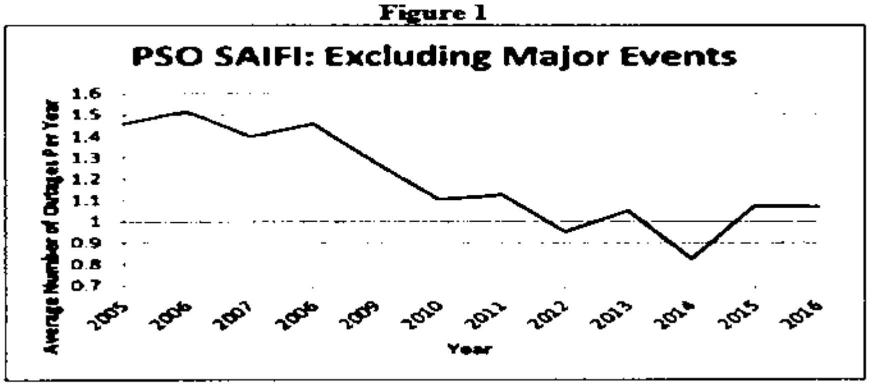


Figure 2

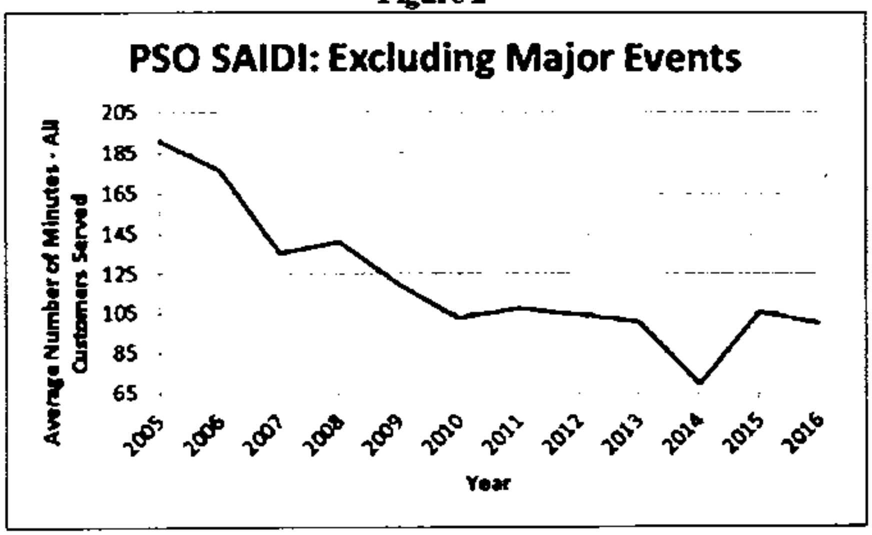
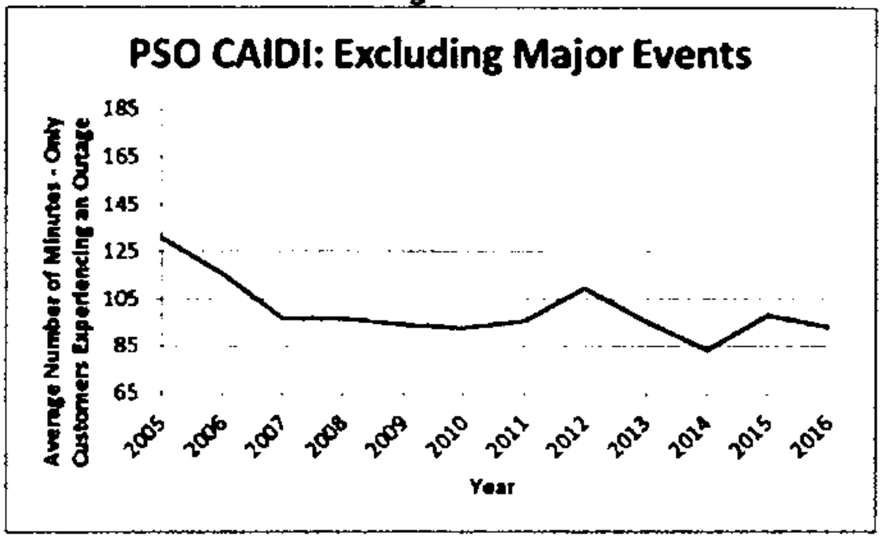


Figure 3



According to Mr. Baker, over the past eleven years, PSO's overall reliability performance has improved dramatically. Since 2005, PSO's SAIDI has improved approximately 48 percent, PSO's SAIFI has improved over 26 percent, and PSO's CAIDI has improved approximately 29 percent.

Mr. Baker testified that PSO's electric system reliability performance compares very favorably to state, regional and national averages. PSO's electric system SAIDI reliability performance is 46 percent better than the mean when compared to other Oklahoma regulated utilities for the period of 2012-2016. PSO's electric system SAIFI reliability performance is 16 percent better than the mean for this same time period.

Similarly, PSO's electric system reliability performance compares favorably on a regional basis. Based on 2015 reliability information published by the U.S. Energy Information Administration (EIA), PSO's SAIDI reliability performance is 17 percent better as compared to regional investor-owned utilities within the Texas, Kansas, Arkansas, and New Mexico regions. Using this same information, PSO's SAIDI reliability performance is 12 percent better when compared to similarly-sized (between 500,000-1,000,000 customers) national investor-owned utilities.

Regarding test year O&M expenses, Mr. Baker testified that the Company's adjusted test year O&M expenses for distribution activities were $92,462,983, which includes approximately $4.4 million associated with a severe storm amortization expense, and an additional $7.6 million to increase the average level of distribution O&M for severe storms.

According to Mr. Baker, to compare the O&M expense level for both rate cases, the adjusted distribution test year amount for the previous rate case (Cause No. PUD 201500208) must be adjusted to account for the impact of the expenses previously recovered through the System Reliability Rider (SRR). The impact of the severe storm amortization expense approved in Cause No. PUD 201300217 is also factored into the comparison of test years shown in Figure 5.

Figure 5

Test Year Comparison Items	PUD 201500208 Adjusted Test Year	2016 Adjusted Test Year (Excluding Storm Expense)
Adjusted O&M	$44,934,106	$92,462,983
SRR Adjustment	$21,725,896	
Severe Storm Amortization	$4,542,570	
Average Level of Severe Storms Increase		$7,630,000
Severe Storm Amortization		$4,392,763
AMI Meter Expense Increase		$4,373,789
Totals	$71,202,572	$76,066,431

Mr. Baker testified that the upper portion of Figure 5 shows the aforementioned SRR and severe storm amortization items, while the lower portion shows increases in the current test year over the prior test year. The increases over the prior test year include $4.4 million associated with severe storm amortization expense, and an additional $7.6 million to increase the average level of distribution O&M for severe storms.

According to Mr. Baker, PSO experienced five severe weather events, or major storms, since the last rate case, which include the following:

- January 1, 2015 – This ice storm impacted PSO's Lawton District, costing $1,409,096 in O&M. Although there were no significant outages associated with this event, the forecasted weather called for freezing rain and ice. PSO had approximately 1,175 employees and contractors ready to respond to power outages.

- May 16, 2015 – This wind storm impacted PSO's Lawton, McAlester, and Tulsa Districts, causing nearly 26,000 customer outages at the peak, and costing $1,061,079 in O&M. Over 570 PSO employees and contractors were mobilized for storm restoration efforts.

- November 27, 2015 – This ice storm impacted PSO's Lawton District, causing over 10,000 customer outages at the peak, and costing $4,256,750 in O&M. Approximately 500 PSO employees and contractors were mobilized for storm restoration efforts.

- December 26, 2015 – This snow storm impacted PSO's Lawton District, causing approximately 23,500 customer outages at the peak, and costing $7,738,424 in O&M. Approximately 900 PSO employees and contractors were mobilized for storm restoration efforts.

- July 14, 2016 – This wind storm impacted PSO's Lawton and Tulsa Districts, causing 109,000 customer outages at the peak, and costing $4,862,325 in O&M.

> Approximately 1,000 PSO employees and contractors were mobilized for storm restoration efforts.

> Mr. Baker further testified that there were other weather events that were pertinent to the case. In early January of 2017, PSO prepared for a forecasted major ice storm which was ultimately predicted to impact a large percentage of PSO's service territory. On Friday, January 6, 2017, PSO began receiving early weather forecasts indicating a severe ice storm was possible during the middle of the following week. PSO continued to monitor all available weather forecasts over the weekend of January 8 and 9, while concurrently beginning preliminary preparations for a major winter weather event. By the evening of Monday, January 9, local weather forecasts, forecasts from the Norman and Tulsa offices of the Nation Weather Service, and forecasts from American Electric Power's Meteorology department were gaining confidence that a significant icing event was likely for all or portions of PSO's three operating districts starting on Wednesday, January 11. In accordance with PSO's pre-defined major event response strategy, PSO began to scale up storm preparations by taking actions such as alerting our staging area partners, inquiring about the availability and location of off-system resources, and staffing our logistical support functions.

> PSO's plans call for the acquisition of additional off-system line vegetation resources to be staged throughout the service territory in advance of the start of winter precipitation (preparation for storms is described in more detail later in my testimony). PSO received the initial wave of line and vegetation resources by January 10, completed safety orientations for all workers, and assigned the off-system resources to work teams and locations in preparation for the start of a wide-spread ice storm. PSO closely monitored weather forecasts and local conditions to determine if additional off-system resources would be required. Although PSO experienced some moderate icing across a wide variety of the state and some isolated pockets of heavier icing, the storm was less severe than predicted in PSO's service territory and the number of customers that experienced outages was relatively low. However, other portions of the state were severely impacted by this weather event. Once it was clear the weather impacts to PSO's service territory would not be significant, PSO immediately began demobilizing our major storm restoration logistical and operational organizations. PSO also began releasing off-system resources to their home base or other neighboring utilities that were requesting additional workers. PSO expended $10,356,294 in preparation for this event, the vast majority of which was for mutual assistance that PSO had acquired.

Mr. Baker testified that the AMI program had provided operational and reliability benefits to PSO's customers and distribution system.

PSO has experienced a variety of benefits from AMI during both normal operations and storm restoration situations. AMI has enabled PSO to identify and correct undesirable system conditions impacting thousands of customers such as low voltage, high voltage, intermittent outages, and identify pending equipment failures such as damaged distribution transformers and overheated meters/meter enclosures before a customer experiences an outage. AMI provides near real-time notification of outages down to the individual customer level without relying upon customers to report an outage to our call centers. AMI allows PSO to monitor and spot check voltage levels at over 540,000 locations across our system, which pinpoints areas requiring immediate attention or longer-term capacity planning needs. AMI allows PSO to selectively "poll" meters remotely to check for voltage and proper meter function without dispatching an employee to the field. PSO has also realized a reduction in outage restoration time during major storm restoration situations stemming from the AMI.

Mr. Baker testified that the two-way communications capabilities of AMI allow PSO to achieve improved customer reliability by alerting PSO to potential reliability issues. In 2016, PSO proactively responded to the following potential customer reliability issues:

- Temperature Alarms: PSO identified 626 events where there was a temperature alarm. Identifying potential high temperatures in the meter enclosure confers the ability to investigate and proactively correct issues. Of these events 453 problems were found, avoiding a potential issue or outage, and 173 no issues were found.

- Voltage Interval Reading Capability: In 2016, 2,073 meter locations were investigated where the meters were reporting multiple events due to a momentary loss of voltage or low voltage. Over one-third of the locations were proactively repaired, which prevented a customer outage and mitigated the need for the customer to contact PSO. The following is the breakdown of these events:

Voltage Interval Reading Metrics	Count
Service connections repaired	788
Diversions identified	390
Vandalism	60
Issue in the meter enclosure	265
Stolen meter	95
Electrician	103
No issues	284

- Voltage Optimization: PSO's AMI meters capture 15-minute average voltage data. Coupling this data with analytics identifies trends where voltage has increased/decreased over time, which may be indicative of a transformer on the verge of failing or other service quality issues. In 2016, 534 locations impacting 2,288 customers were identified that had possible power quality issues indicating either high or low voltage conditions. The following issues were proactively identified, and the equipment was repaired or replaced prior to the equipment failing and avoiding a potential outage:

Voltage Optimization Metrics	Count
Transformer changed	129
Incorrect meter installed	48
*PSO voltage regulation equipment	296
Service Repair	61

*Regulators, capacitor banks, transformer LTC

Mr. Baker further testified that a fundamental component of any storm restoration plan is accurately determining the number of customers interrupted and their relative location on the electrical grid. To determine the location and number of customers interrupted, PSO has traditionally relied upon high-level system indications from our Supervisory Control and Data

Acquisition (SCADA) equipment. Our SCADA locations help us determine in most situations if a transmission line has faulted and, to a lesser degree, if a substation or distribution feeder is out of service. Information at this level is critically important to the operation of the electric grid overall, but does not provide detailed information at the individual customer level.

Prior to the recent installation of PSO's AMI meters, we were not aware, with any precision, of the level of individual customer outages. Our only indication of a customer outage in instances that did not trigger a high level SCADA notification occurred when customers telephoned to report an outage to our call centers. During a storm restoration event, a lack of specific and more precise outage information at the individual customer level creates a variety of operational challenges. Without accurate lower-level system information in the field, more personnel resources are required to physically "sweep" an area in a yard-to-yard manner to locate isolated customer outages versus having the intelligence to pinpoint a customer outage. The end result of less customer-specific outage information is longer restoration periods, increased operating expense and limited information to communicate with customers.

According to Mr. Baker, now that PSO's new AMI meters are in place, we know down to the individual meter location if a customer's electric service is interrupted without relying upon customers to call and report an outage. Similarly, we can use the AMI meter "polling" process to electronically verify electric service to customers has been restored and proactively search for isolated outages in an area thought to be restored without using the cumbersome yard-to-yard sweep process. In the case of the July 14, 2016 wind storm that impacted PSO's Tulsa service territory, we were able to poll hundreds of thousands of meters overnight on the second full day of the recovery effort to verify electric service was restored without sending field resources to individual customer locations. The information provided by the AMI polling process allowed us to make specific restoration resource work assignments prior to the start of work the next morning and avoid the time-consuming and costly yard-to-yard sweep process described earlier. The AMI-enabled process allowed us to wrap up the recovery efforts and restore electric service to the remaining customers approximately 24 hours earlier than would have been possible without the benefit of the AMI polling process. PSO was also able to release the majority of the off-system resources roughly 24 hours earlier versus what our pre-AMI restoration processes would allow.

According to Mr. Baker, in previous base rate cases, the assertion has been made that PSO's removal costs for certain distribution facilities, such as poles, are high as compared to the removal costs of other AEP operating companies.

Mr. Baker has responsibility over both the construction of distribution facilities, as well as the removal of distribution facilities for PSO. Removal costs are the costs associated with removing distribution assets from service. This includes costs such as labor and equipment.

Mr. Baker testified that PSO's removal costs are impacted by a number of factors, including PSO's aggressive system maintenance and replacement program (including the worst performing circuit program). As a part of this program, PSO replaces deteriorated facilities in difficult locations and applications, such as inaccessible easements and multi-circuit structures. Because of the challenging nature of these projects, they naturally have a higher removal cost, which can impact one of the individual cost of removal categories, like distribution poles.

However, when viewed in the broader context of PSO's total distribution removal costs, PSO's removal costs continue to appear reasonable when compared, for example, to other AEP companies.

PSO removed approximately 74 percent more poles per mile and approximately 117 percent more cross-arms per mile than the AEP system average for the period of 2016. These increased volumes occurred due to PSO's aggressive maintenance and replacement program. This activity is a core component of PSO's reliability performance as discussed in Section VI of my testimony. Also, as I discussed in Section VI of my direct testimony, PSO's electric system SAIDI reliability performance is 46 percent better when compared to other Oklahoma regulated utilities for the period of 2012-2016. Similarly, PSO's SAIDI reliability performance is 17 percent better as compared to regional investor-owned utilities, and 12 percent better when compared to similarly-sized national investor-owned utilities. This aggressive maintenance and replacement program, while providing reliability benefits, does tend to increase PSO's removal cost. Nevertheless, PSO's removal costs are necessary and reasonable and are managed cost effectively.

DONALD R. DOHRMANN

Dr. Donald R. Dohrmann, Principal and Director of Economics at ADM Associates, Inc. ("ADM"), testified on behalf of PSO.

Dr. Dohrmann testified that ADM was established in 1979 and has performed extensive work related to evaluating energy and demand programs and measuring associated savings. Specific to this Cause, ADM was retained to perform evaluation and savings measurements of PSO's PowerHours® programs.

According to Dr. Dohrmann, PSO has embarked on a campaign to cultivate a significant Demand Response (DR) resource. PSO used 2016 as a design and development or "experimentation" year which has resulted in a verified peak demand reduction of 5.81 MW through Direct Load Control events and the higher-cost time of day. In addition to demand reduction, the program achieved energy savings. The energy savings and demand reductions resulted in financial savings for program participants. On average, each participant saved $26 during PSO's on-peak months of May through October. Additionally, customers that participated in direct load control (DLC) events, on average, received approximately $12 in bill credits during the summer of 2016.

Dr. Dohrmann further testified that ADM's made recommendations to PSO for the PowerHours® program, and they can be characterized in two groups. The first set of recommendations concern the customer enrollment and device registration process, while the second set of recommendations are suggestions that might be characterized as continuous improvement efforts for the program.

Dr. Dohrmann testified that based on ADM's evaluation, he believed PSO has identified a viable, scalable, technical solution. They utilized 2016 as a "design and development" or "experimentation" year, and have taken steps to refine their program design based on data from the 2016 evaluation.

Dr. Dohrmann further testified that it appears that the 2016 PowerHours® program achieved similar technical performance as a mature DR program of similar design. As such, optimization of air conditioner cycling strategies or a reduction of non-responding device rates may yield a relatively small amount of improvement. Increased thermostat registration rates, however, can yield significant improvements to the program. Based on PSO's strategic marketing plan, this improvement could potentially be realized with relatively little cost, given that they may not require further infrastructural expenditures. Initial evaluation results from 2016 indicate that PSO's 2013 demand reduction projections seem reasonable and achievable, and have developed a pathway toward achieving those goals.

Derek S. Lewellen

Mr. Derek S. Lewellen, Meter Infrastructure & Program Development Manager for Public Service Company of Oklahoma (PSO or Company), testified on behalf of PSO.

Mr. Lewellen testified that Advanced Meter Infrastructure ("AMI") System refers to systems that measure, collect, and analyze energy usage from meters through a communications network. This infrastructure includes hardware, such as meters, that enable two-way communications, and a communications network that provides the communication path between the meters and PSO's Information Technology (IT) systems. PSO's IT systems include the customer information systems, meter data management system, analytics hub, and the customer webportal. These IT systems utilize the AMI data to provide useful information to customers.

According to Mr. Lewellen, in 2013, PSO developed an initial project plan to install AMI meters, network equipment, and supporting IT systems. The plan and projected costs were based upon the experience gained with PSO's pilots, lessons learned from other utilities like AEP Texas and Oklahoma Gas and Electric (OG&E), PSO's procurement experience, and available pricing.

In early 2014, PSO refined the project plan to incorporate details such as the bidding processes for material and various contract resources, material delivery schedules, supporting IT projects, network design, meter and network installation schedules, customer communication plans, and consumer program development. All of these steps were layered into the project plan to ensure timely completion of the three-year project.

Mr. Lewellen testified that PSO competitively bid all aspects of the project to ensure requirements were met at the best available pricing. For example, PSO sought bids from multiple AMI communication providers for components such as network equipment and associated IT systems, meter vendors, meter installation contractors, network equipment installation contractors, and customer webportal providers.

Mr. Lewellen further testified that prior to and during AMI meter installation, PSO provided customers information about AMI, the customer webportal and associated Consumer Programs. This communication took place through multiple communications channels. For communications related specifically to the meter exchange, the following direct customer contact channels were used:

- <u>Customer Letter</u>: This was the initial contact in the form of a letter informing customers of their projected meter installation date. The letter was sent out approximately four to eight weeks prior to the new meter installation. Approximately 533,000 letters were sent to homes or businesses.

- <u>Phone Blast Message</u>: As a reminder of impending installations, customers were notified via phone message one to four weeks prior to the new meter installation.

- <u>Door Hanger</u>: At the time meters were exchanged, door hangers were left to inform customers that their existing meters had been exchanged for an AMI meter and how to contact PSO if they had any questions or concerns. The door hanger also included information about the meter, including benefits of AMI and how to access the customer webportal.

According to Mr. Lewellen, aside from minor cleanup, PSO completed deployment ahead of schedule in July 2016. In addition to deploying ahead of schedule, more meters were installed than originally projected, additional functionality such as an enhanced webportal was made available, and the project came in under budget.

The final project costs are $110,811,458 in capital expenditures, and $13,757,961 of O&M expenses for the AMI deployment period of 2014 through 2016. These totals are approximately $8.9 million and $6.7 million under the original cost estimates respectively.

Figure 2

AMI Program	2014-2016 Projected	2014-2016 Actual	Amount Under Budget
Capital Spend – project	($119.7 million)	($110.8 million)	$8.9 million
O&M Spend - project	($20.5 million)	($13.8 million)	$6.7 million

Mr. Lewellen testified that PSO was able to leverage its purchasing power to obtain a lower cost for AMI meters and network equipment. This was the largest contributor to the decrease in capital costs because the projected capital cost per customer dropped significantly from the pre-deployment projection of $230 to $208 actual.

In terms of the reduced O&M costs, employee severance costs were approximately $2.0 million less than projected, staffing and salaries for new positions were $2.5 million less than the projected expense, and costs associated with the network and IT components were approximately $2.0 million less than originally projected. The staffing for new positions associated with AMI was also less than projected, which is an ongoing savings greater than originally projected according to Mr. Lewellen.

Mr. Lewellen testified that in Cause No. PUD 201300217, PSO projected a $5.0 million savings during the three-year deployment period and an additional $6 million in the first full year after deployment. In 2014 through 2016, PSO realized over $8.85 million in associated labor, overhead and vehicle savings, which is $3.35 million greater than the projected $5 million. PSO is also on target to achieve over $6 million in annualized labor, overhead and vehicle savings in 2017.

This savings represents the elimination of all 59 meter reader positions, the reduction of the field meter services staff from 52 employees to 28, and the elimination of two clerical positions. This is a total of 85 positions, as well as the associated vehicles, which equals the number of employee and vehicle reductions projected in Cause No. PUD 201300217. Current headcount and payroll are not expected to reduce further beyond the test year end.

Associated with the staffing and vehicle reductions, PSO avoided over 525,000 truck rolls and 1.3 million miles during 2016. This is approximately 60 percent less than the amount of miles driven prior to the deployment of AMI. PSO anticipates further mileage reductions in 2017 and is projected to meet or exceed the original projection of reducing miles driven by 75 percent or approximately 1.5 million miles.

Mr. Lewellen testified that the $11 million of guaranteed savings will be passed through to customers by the end of 2017.

According to Mr. Lewellen, with the ability to automate the disconnect and reconnect process of customer delinquent accounts, PSO is able to reduce the annual amount of charge-offs. Prior to the deployment of AMI, the three-year average for charge-offs was almost $6 million annually. In 2016, even though AMI was not yet fully deployed, the charge-off amount was slightly over $5 million, which represents an approximately $1 million reduction in bad debt. This reduction benefits all customers because it reduces the amount of uncollected billings that is passed through to all customers.

The charge-off reduction was accomplished through a combination of factors, mainly the ability to process almost 100 percent of the credit disconnects, and the ability to process credit disconnects after a moratorium. Prior to AMI, this was a manual process constrained due to the number of available resources, which allowed some customers to increase the delinquency period another 30 days. Also, having the ability to remotely connect/disconnect at the meter has eliminated the reconnect fee and reduced the number of services disconnected at the pole due to an inaccessible meter.

Mr. Lewellen further testified that now that AMI is fully deployed and PSO is offering Power PaySM (prepaid billing), PSO is expecting charge-offs to be further reduced in 2017, beyond the $1.6 million achieved over the deployment period (this is slightly less than the original projection of $1.7 million reduction during the same period). This expectation is based upon the experiences of other electric utilities with prepay programs that have created a positive impact on charge-offs. This is attributed to Power PaySM customers being able to defer up to $500 of past-due amounts coupled with the ability to pay the deferred amount over time.

AMI enables a reduction in both theft and consumption on inactive meters through the use of analytics and the installation of a remote disconnect switch in meters. Identifying and stopping theft faster has a positive impact on reducing the unknown amount of stolen or unaccounted-for energy. Prior to AMI (2012 through 2014), PSO investigated on average over

3,900 cases of theft annually. In 2016, AMI enabled PSO to investigate over 6,100 cases, which is a 60 percent increase in theft investigations.

For usage on inactive accounts, during the same three-year period prior to AMI, PSO identified over 4,600 inactive accounts that showed usage. Prior to AMI, these were found by field personnel during monthly meter reading in instances where the meter had been energized. Since the completion of AMI, this has declined to approximately ten inactive accounts having usage per month. At the most conservative end, using only the cases of theft that PSO identified in 2015 and 2016, PSO realized approximately $565,000 of savings in theft and usage on inactive meters.

Mr. Lewellen testified that obsolete meter avoidance creates a one-time avoided investment by replacing meters during the deployment period at the end of their useful lives and scheduled to be replaced due to manufacturer bulletins, testing, and field observations. PSO conservatively projected $1.2 million in avoided investment during the deployment period; however, the actual avoided investment was approximately $9.1 million. On average, PSO replaced over 16,000 meters annually due to obsolescence prior to the AMI deployment. This equates to over 48,000 meters during the three-year deployment. By replacing these meters with an AMI meter, the replacement costs associated with these meters are avoided.

According to Mr. Lewellen, AMI provides billing and call center efficiencies by reducing call volume and enabling employees to address inquiries in a more expeditious manner. Calls associated with billing, credit and investigation orders, which are approximately 40 percent of the annual call volume, have been reduced approximately 14 percent in 2016 alone. In comparing the annual call volume prior to AMI deployment (2012 through 2014) to the deployment timeframe (2015 and 2016), PSO received over 190,000 fewer phone calls. Based on an estimated cost per transaction, this reduction in phone calls represents a productivity savings of approximately $395,000 versus the original projection of $91,000. This amount will likely increase now that AMI is fully deployed.

Mr. Lewellen concluded by stating that PSO completed the installation of approximately 533,000 AMI meters ahead of schedule and under budget by over seven percent in capital expenditures and 33 percent in O&M expenditures. Further, despite being fully deployed for less than one year, operational, reliability, and customer experience benefits are already being realized at significant levels, many beyond original projections.

JOHN O. AARON

Mr. John O. Aaron, Manager, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), testified on behalf of PSO.

Mr. Aaron testified that he prepared PSO's jurisdictional and class cost-of-service studies and the development of the jurisdictional and class allocations and related Application Package (AP) schedules as required by OAC 165:70-5-4 and the Supplemental Package (SP) workpapers as required by OAC 165:70-5-20. While the Company's resources are predominantly used to provide service to Oklahoma retail customers (in excess of 99% of PSO's rate base is assigned to the Oklahoma retail jurisdiction as shown in Schedule K), OAC 165:70-5-4 requires the jurisdictional separation of the Company's rate base, revenues, expenses, and other applicable items. Mr. Aaron also supports the pro forma adjustments made to the test year customer, revenue, and sales volume data.

According to Mr. Aaron, a cost-of-service study allocates or assigns cost responsibility. PSO provides electric service at retail in Oklahoma subject to the jurisdiction of the OCC and to wholesale customers subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Since PSO incurs costs to provide service to customers in two jurisdictions, a jurisdictional cost-of-service study is necessary to allocate or assign these costs, as measured by the total Company revenue requirement, to the appropriate jurisdiction to determine the cost-of-service for that specific jurisdiction. This is achieved in the jurisdictional cost-of-service study. Once the jurisdictional costs are determined, a class (e.g., residential, commercial, industrial, municipal and outdoor lighting) cost-of-service allocates or assigns the jurisdictional cost-of-service to the different classes based on the customers' use of PSO's electric system. The result is a fully-allocated embedded cost-of-service study that establishes the cost responsibility for each jurisdiction. An embedded class cost-of-service study assigns the retail jurisdictionally-allocated total Company costs to the individual retail customer classes to evaluate the cost PSO incurs in providing electric service to each individual retail customer class.

Mr. Aaron testified that a cost-of-service study relies on the utility company's historical test year accounting records to establish cost levels for rate base and expenses. Selected AP schedules and SP workpapers are the source of the cost levels for rate base and expenses in this cost-of-service study. The costs recorded in each FERC account are typically adjusted to reflect the applicable regulatory commission's policies and for known and measurable changes to the test year level of expenditures. Operating statistics such as peak demands, energy sales, customer counts and other data support the allocation of the costs to jurisdictions and classes.

A three-step process is followed to assign costs to the customer classes: functionalization, classification, and allocation.

According to Mr. Aaron, in the first step, the costs are separated by function (e.g., production, transmission, distribution, and customer services).

The second step in preparing a cost-of-service study is to separate the functionalized costs based on the characteristics of the electric service provided. The major cost classifications are demand-related costs, energy-related costs, and customer-related costs.

According to Mr. Aaron, the final step of the three-step process in preparing a cost-of-service study is to allocate the functional classified costs both to jurisdictions and classes of customers. The nature of the service provided and the load characteristics for each cost item such as peak demand (kW), energy consumed (kWh), or number of customers, serves as the basis for this allocation process.

The allocation process involves dividing the functionalized and classified costs among the jurisdictions and customer classes. The objective of this process is to assign costs in a reasonable and understandable way. Some costs are directly assignable to a single jurisdiction, a single class or even a single customer. For example, the cost associated with the poles and luminaires used for street lighting are directly assigned to the street lighting class.

Most costs, however, are attributable to more than one type of customer. These joint costs must be allocated to customer classes by an allocation methodology that recognizes each class's contribution to the cost driver such as peak demand, energy consumed, or the number of customers. This allocation ultimately determines the overall level of cost for the utility service provided.

Regarding transmission costs, Mr. Aaron testified that the Commission ordered the use of a 4-CP allocation based on testimony from other parties that stated PSO is a summer peaking utility, and therefore, it is appropriate to reflect the cost to use the transmission system during the four peak months (June through September) rather than all twelve months.

Mr. Aaron did not agree with use of a 4-CP allocation because the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) invoices transmission service customers, such as PSO, based on a 12-CP allocation. Therefore, the 12-CP transmission allocation methodology is the most appropriate allocation methodology for PSO's retail classes. Moreover, with the FERC-approved SPP RTO responsible for the planning and construction of the regional transmission system, the individual utility systems' (PSO in this case) load characteristics are no longer the primary driver in how transmission costs are determined. Historically, PSO planned and built its transmission system to serve its own retail and wholesale native load. That is no longer the case. According to Mr. Aaron, SPP now has functional control of PSO's transmission assets to meet regional and local needs; therefore, what has been done historically in regards to transmission planning and constructing as a basis for determining the appropriate transmission allocation, no longer exists.

Mr. Aaron testified that the 12-CP allocation of transmission costs reflects how PSO's customers use the transmission system as well as the method in which the charges by SPP are assessed. The customers that benefit from the use of the transmission system also bear their appropriate cost responsibility for their use of the transmission system. The 12-CP transmission allocation is the cost causation principle based on the activity that drives the costs.

Mr. Aaron stated that the 12-CP transmission allocation reflects the customers' actual use of the transmission system and the costs incurred by PSO in providing that service. Following the principle of cost causation, PSO's larger customers and users of the SPP transmission system should bear a larger and more equitable share of the costs billed by SPP.

Mr. Aaron testified that the cost-of-service studies were developed in a manner consistent with the studies preciously filed by PSO with the OCC.

Mr. Aaron further testified that the jurisdictional cost-of-service study is used to allocate costs between the retail and wholesale (FERC jurisdictional) customers. The jurisdictional allocations of rate base, revenues, and expenses shown in AP Schedules K-1 through K-3 are used in various accounting schedules to determine the costs and revenues that are applicable to the retail jurisdiction. The costs and revenues applicable to PSO's retail jurisdiction are then used in the retail customer class cost-of-service study as provided in SP WP L.

The results of the class cost-of-service are primarily used to: (1) provide embedded cost information that can be used as one tool in developing the pricing structures for each customer class, (2) provide information with which present and proposed relative rates of return by customer class can be compared and reviewed, and (3) comply with OCC filing requirements.

According to Mr. Aaron, all of the adjustments discussed by PSO witness Randall W. Hamlett and in his testimony are reflected in the jurisdictional and class cost-of-service studies submitted in this proceeding.

STEVEN L. FATE

Mr. Steven L. Fate, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO or Company), an operating company subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Fate testified that PSO provides high-quality electric service at reasonable prices to its customers. PSO's 547,000 customers represent a population of approximately 1.9 million Oklahomans spread over 232 cities and 30,000 square miles. PSO has 1,574 Oklahoma-based employees, maintains 20,100 miles of distribution lines, 3,200 miles of transmission lines, and 3,788 megawatts of power generation. PSO continually strives to deliver ever-higher quality of service at reasonable rates. In April 2017, PSO received a J.D. Power & Associates residential customer satisfaction score of 725 and is in the second quartile of our peer companies and ranked 51 out of 138 national brands. While we are pleased with this achievement, we understand our customers' expectations are also increasing and we are continuing to work hard to consistently meet and exceed customer expectations.

The deployment of AMI across our service territory has opened a new frontier in our ability to serve customers, allowing us to restore power more quickly, improve system reliability, offer more pricing options to choose from, and provide more information so customers can better manage their energy usage and control costs.

System reliability is a key component of customer satisfaction and we continue to focus on delivering power at a consistently high level with infrequent outages of short duration. PSO's system reliability compares very favorably to state, regional and national averages. A key reliability metric, the System Average Interruption Duration Index (SAIDI), is 46 percent better than average when compared to other Oklahoma regulated utilities for the period of 2012-2016. PSO's proven record of rapid service restoration from storms is being further enhanced by individual customer outage information now available in real-time through AMI.

Nineteen percent of the J.D. Power & Associates survey composite result is related to price. PSO is currently near the first quartile in satisfaction with price. These ratings are evidence of PSO's ability to deliver increasing customer satisfaction while maintaining reasonable rates. Between 2007 through 2016, PSO's residential price increased at a 0.8% annual growth rate as compared to U.S. electricity growth rate of 2.1%.

Mr. Fate testified that the use of the historical test year, along with the disallowance of some prudently-incurred costs and known and measureable adjustments, contributed to the regulatory lag experienced by the Company and has not provided PSO a reasonable opportunity to earn its authorized return on common equity. The disallowance of reasonably-incurred costs does not promote economic efficiency or result in fair, just, and reasonable rates. Ultimately, PSO's inability to approach its authorized return on equity (ROE) will hamper the Company's ability to attract the capital necessary to invest in our system and continue to effectively and reliably serve our customers.

	Table 1 Return on Common Equity	
	Earned	Authorized
2016	8.52%	9.50%
2015	8.62%	9.85%
2014	8.86%	10.15%

According to Mr. Fate, approval of appropriate depreciation rates is necessary to maintain adequate cash flow and is an essential component of fair rate relief. Preparing for the increasing rate of change in the industry necessitates that the Commission also focus on setting reasonable depreciation rates. The current depreciation rates do not recover the cost of the investment over a reasonable asset life.

Mr. Fate testified that the primary reason PSO was filing a base rate application at this time was the increase in expenses since its last rate case that is necessary for PSO to continue providing quality service to its customers. In addition to increasing transmission and distribution expense, since the last rate case PSO has approximately $625 million of additional investment not currently reflected in rates. Due to these increases, as well as adjustments adopted by this Commission to PSO's cost of service in Final Order Nos. 657877 and 658529 issued in Cause No. PUD 201500208, PSO's 2016 earned ROE was 8.52%, almost a full 100 basis points below its authorized return on common equity of 9.5% granted in November 2016.

Further, the two major cost recovery issues addressed in PSO's application are the inclusion in base rates of the remaining portions of PSO's full cost of the ECP and the AMI, which collectively represent a $335 million investment. Both of these investments are important steps in PSO's long-term strategic change intended to prepare the Company and customers for changes in the electric utility industry.

Mr. Fate further testified that PSO is requesting a base rate increase of approximately $170 million. This increase is due primarily to a revenue deficiency based on a test year ending December 31, 2016, adjusted for known and measurable changes to test year levels. Also as part of the increase, pursuant to Order No. 657877 issued in Cause No. PUD 201500208, PSO's request includes the consolidation into base rates the investment and expenses, net of savings, currently recovered through the AMI rider.

The total rate impact, which also includes the elimination of the remaining Distribution System Reliability Capital Carrying Costs recovered through the System Reliability Rider (SRR), results in an increase to PSO customers' rates of 11.5%.

According to Mr. Fate, the primary changes are as follows (dollars in millions):

Category	Cost
Depreciation	$58
Operation and maintenance	50
Income taxes	25
Other taxes	5
Return and other	42
Less Additional Revenues	(11)
Less Elimination of AMI Rider	(9)
Less Elimination of SRR	(3)
Change in Total Revenue	$156

Mr. Fate testified that depreciation has increased both due to higher levels of depreciable plant, as PSO has made additional investment in electric assets to serve customers, and the proposed increase in depreciation rates.

Operation and maintenance expenses have increased largely from higher Southwest Power Pool (SPP) transmission service and the distribution function. Much of the increase in the distribution function is related to storm expense.

Income taxes have grown because of the tax effect of the return on a growing rate base. Property taxes have increased due to a higher taxable base. Return and other increases are predominantly from the higher costs of financing the increased investments in electric utility assets.

Revenues have increased since the last test year used to set rates, which reduces the overall revenue requirement. The increased revenues are mostly from SPP transmission service revenues, miscellaneous revenue and slightly higher numbers of customers resulting in increased total kilowatt-hour sales.

Mr. Fate also testified that PSO is requesting OCC approval for: (1) recovery of and return on the cost of the environmental controls at Northeastern Unit 3 and Comanche Power Station (including deferred costs) and (2) recovery through depreciation rates and return on the remaining undepreciated book value of Northeastern Unit 4 by 2040. Environmental controls for Northeastern Unit 3 and Comanche went into service during the test year on February 26, 2016, and June 29, 2016, respectively. Northeastern Unit 4 was removed from service in April 2016.

According to Mr. Fate, the total cost for Northeastern Unit 3 controls, including AFUDC, was $180 million. The total cost for Comanche, including AFUDC, was $43 million. In sum, these investments were prudently managed, below their estimated cost, were reasonably incurred, and are currently serving customers.

Mr. Fate stated that if the Commission does not allow PSO to recover the cost of and receive a full return on Northeastern Unit 4 there would be significant negative financial implications for the Company. Beyond the negative financial implication for the Company, disallowing recovery of the shareholders' investment in an asset that served customers for 46 years, well beyond the original retirement date, it would send a perverse signal to the Company that its investment decisions should not be based on what it believes are in the best interest of customers, but alternatively decisions should focus on keeping assets in operation as long as possible – regardless of the cost and risk to customers. Stated differently, such an outcome will signal to management that if PSO had invested $750 million in environmental controls to keep Unit 4 in service, in spite of the strong evidence that to do so might not be in the long-term interest of customers, PSO could have avoided a negative financial outcome and increased its earnings rate base. This perverse incentive could have a negative effect on the making of good investment decisions in Oklahoma, and would be counter to the long-term interests of customers.

Mr. Fate testified that the Commission authorized PSO to recover various AMI-related costs net of guaranteed savings through the AMI rider. The Commission found among other things that:

1. The approximately $16 million of AMI investment as of January 31, 2014, was used and useful and should be recovered in base rates;

2. A regulatory asset should be created for the unrecovered net book value of non-AMI meters replaced by AMI meters to be amortized using a 9.58% depreciation rate;

3. PSO is required to guarantee $11 million in savings associated with labor, vehicles, and overheads over the first four years of AMI implementation; and

4. Creation of the AMI tariff to recover the investment cost of AMI using over/under accounting and recording as a regulatory asset, or regulatory liability, the difference between actual AMI revenue requirement and actual revenues collected under the tariff.

According to Mr. Fate, the Order stated that additional levels of AMI investment may be found used and useful by the Commission in future regulatory proceedings and that PSO must demonstrate that the purported benefits either have or will be delivered to customers. The Order also stated that the AMI tariff would remain in effect until the first base rate case subsequent to the full implementation of AMI. In 2016, PSO fully completed the AMI deployment and is now requesting the Commission make a finding that the additional AMI investment is used and useful and recoverable through base rates.

TOMMY J. SLATER

Tommy J. Slater, Vice President-Generating Assets for Public Service Company of Oklahoma, testified on behalf of PSO.

Mr. Slater testified that capital and O&M expenditures for PSO's fossil fuel generation were prudent, reasonable and necessary to maintain a safe, reliable, and environmentally-compliant generation fleet. O&M expenditures for the coal and gas-fired plants have decreased to a three-year average level of $81.0 million. With the retirement of Northeastern Unit 4, this represents a reasonable and sufficient ongoing level of O&M for the fleet.

According to Mr. Slater, capital projects and expenditures were undertaken to address environmental requirements, performance, reliability, or safety priorities at the generating plants. Since PSO's last base rate case, environmental controls at Northeastern Unit 3 and Comanche Power Station were completed and placed in service for $224.6 million - a combined $9.9 million under budget - and are operating as expected to help the plants meet environmental requirements.

Mr. Slater further testified that PSO owns and operates seven generation plants consisting of 18 units that are located within the state of Oklahoma. In addition, PSO owns approximately 15.6% of, and operates, the Oklaunion Power Station, located in Vernon, Texas.

Excluding other capacity entitlements that are used to meet the minimum Southwest Power Pool reserve margin requirement, PSO owns a net generating capacity of approximately 3,927 MW. Based on fuel type, PSO's generating units are approximately 15% (or 571 MW) coal-fired capacity and 85% (or 3,356 MW) natural gas-fired capacity.

Mr. Slater testified that environmental controls were installed at Northeastern Unit 3 to meet the requirements of the Mercury and Air Toxics Rule (MATS) and the Regional Haze Rule (RHR). The estimated project cost in 2015 of Northeastern Unit 3 environmental controls project was $190.6 million and the final completed cost as of the end of this test year was $181.2 million. The systems were placed in service on February 26, 2016, and the environmental emissions controls are operating reliably and performing as expected.

Mr. Slater testified that to achieve compliance with the Oklahoma Regional Haze State Implementation Plan for Nitrogen Oxide (NOx) emissions, low NOx burners were installed on Comanche 1G1 and 1G2 natural gas-fired combustion turbines. Other modifications were made at Comanche to improve the gas supply system , to upgrade turbine controls to support the additional requirements of the new equipment, and to make safety upgrades to the turbine building to meet Occupational Safety and Health Administration (OSHA) safety requirements.

The cost estimate for environmental controls at Comanche was $43.9 million and the completed cost was $43.4 million. The Low NOx burners and associated improvements were placed in service June 30, 2016 and have operated reliably.

Mr. Slater further testified that Northeastern Unit 4 was retired in place on April 15, 2016.

With respect to O&M expenditures, Mr. Slater testified that PSO's adjusted test year generation non-fuel O&M is approximately $80.2 million.

Mr. Slater further testified that three adjustments were made to test year generation O&M to adjust for known and measurable items. First, an adjustment was made to remove non-recurring O&M expenses resulting from the retirement of Northeastern Unit 4. Second, an adjustment was made to reflect the additional O&M required due to the environmental retrofits installed in 2016. Third, an adjustment was made to normalize the test year O&M amount with historic O&M levels (excluding Northeastern Unit 4). These three adjustments were added to the cost of service to accurately reflect the ongoing level of generation O&M expense for PSO.

Mr. Slater testified that PSO has added approximately $290.1 million to generation plant in service since Cause No. PUD 201500208. Of that total, $255.8 million is associated with major capital projects that had a cost greater than $500,000. In addition to the environmental controls, investments ranged from cooling tower replacement to upgrading turbine control systems. The breakdown of generation plant in service was summarized by Mr. Slater in Table 4 of his testimony.

With respect to retirement dates of the generating units, Mr. Slater testified that the expected useful life of a power plant depends on many factors, including the original design, the current condition of the unit, the operational demands on the unit and the potential cost in the future to replace the generation with another resource. An expected unit life does not represent a firm retirement date, but instead represents a best estimate of the expected operating life of such unit. It is assumed that at the end of the useful life of the unit, it will be economically beneficial to replace the unit with new generation rather than to continue to maintain it.

According to Mr. Slater, the expected useful life of a generating unit is determined with input from many groups. PSO operations staff and American Electric Power Service Corporation (AEPSC) Generation organization engineers routinely track any issues that arise during normal operation or that are found during equipment inspections.

With input from each of the groups, the condition of major equipment-planned capital investments, O&M expense levels, compliance with existing and expected environmental regulations, and replacement generation costs are all evaluated to create a reasonable assessment of the operating condition of each generating unit and determine the expected useful life. This allows PSO and AEPSC to best plan the future of the generating fleet, and ensure that a judicious approach is taken to provide a reliable supply of electricity for PSO's customers at reasonable prices.

Mr. Slater testified that AEPSC provides PSO generation with executive leadership, management direction, and staff support. Both PSO and AEPSC focus on the safe, reliable and low-cost operation of PSO's generation fleet for the benefit of its customers. This relationship is enhanced through the sharing of best practices and lessons learned.

While AEPSC provides planning, engineering and management support activities, PSO management is responsible for directing PSO generation employees in the day-to-day operation and maintenance of PSO's fleet of power plants, and serving as the interface between the plants and AEPSC. PSO employees at the plant level perform routine maintenance on PSO's power plants that may include predictive, preventive, and corrective maintenance.

Because AEPSC provides support to a large number of power plants, it is possible for PSO to have access to generation-related information and knowledge that is not readily available within the PSO organization. This synergy not only helps PSO operationally, but because the AEPSC charges are spread over a number of AEP operating companies, the cost to each AEP company is reduced. This means that it is not necessary for PSO to provide this level of support for its own organization on a stand-alone basis, which decreases the overall cost to PSO customers while maximizing the benefit of the knowledge accumulated from power plants across the country.

JENNIFER L. JACKSON

Jennifer L. Jackson. a Regulatory Consultant in Regulated Pricing and Analysis, part of the American Electric Power Service Corporation (AEPSC) Regulatory Services Department, testified on behalf of PSO.

Ms. Jackson testified that PSO is requesting a change in retail base rates of $169.5 million. The requested change includes approximately $146 million in new base rate increases and approximately $24 million from two riders transitioning to base rates. The riders and associated test year revenue requirements are the Advanced Metering Infrastructure Tariff (AMI), with a test year revenue requirement of approximately $21 million and the System Reliability Rider (SRR) with a test year revenue requirement of $3 million. According to Ms. Jackson, PSO has followed the revenue distribution recommendation from the Final Order in the most recent rate case, Cause No. PUD201500208, to assign the total revenue requirement change to the retail rate classes. EXHIBIT JLJ-1 details the revenue distribution by retail rate class. PSO's request results in a total retail change of approximately 11.43%. The total bill effect on the major rate classes as shown in EXHIBIT JLJ-1 is as follows:

- Residential Class 13.95%
- Commercial Class 9.66%
- Large Industrial Class 8.65%
- Lighting Class 15.76%

Ms. Jackson further testified that for an average residential customer using 1,100 kWh per month, the total bill change is approximately $14 per month.

Ms. Jackson stated that the current rate structures serve customers of all usage types including residential, small commercial, large commercial and small industrial, large industrial, municipal, and lighting. The PSO rate design is based on rate schedules that are differentiated by usage type, energy usage level, demand level, load factor, use of the system, and service voltage levels. Customers are grouped together by similar usage patterns and the costs to serve each class of customer are recovered through a mix of base service charges that recover a portion of the fixed costs of serving customers that generally do not vary with the demand or energy use of the customer, seasonal energy charges that vary with the monthly kWh usage of the customers, ratcheted demand charges based on a customer's maximum load required for service, and minimum bill components. Each of the components recovers costs associated with the generation, transmission, distribution, and customer service functions, and each rate schedule is designed to recover the costs of serving each customer class based on the type of customer and the mix of requirements needed to serve each class of customers.

According to Ms. Jackson, PSO was not proposing to make major changes to the rate structures of the retail rate schedules in this cause.

In this filing, PSO is proposing to continue the class definitions, structures, and basic principles of its rate design recently approved in Order Nos. 657877/658529 from Cause No. PUD201500208 and is not proposing any structural changes to its rate schedules.

Ms. Jackson testified that PSO was proposing new rate options. PSO is requesting approval of new rates for optional LED lighting service available for municipal service customers. PSO is also requesting approval of a methodology to adjust the amount of ad valorem taxes recovered from customers through their base rates. The currently-approved Tax Adjustment Rider has been modified to accommodate this request.

PSO is proposing to terminate the currently-approved SRR and the AMI Tariff through this filing. The SRR will no longer be used to recover additional distribution system reliability expenses or capital carrying costs (per the Order in PUD 201500208) and will expire when compliance rates are approved and in effect through a final order in the current proceeding. Similarly, the AMI tariff will remain in effect until compliance rates are approved and in effect based on the final order in the current proceeding. At that time the AMI Tariff will also expire. The revenue requirements associated with these terminated tariffs are proposed to be recovered through base rates in this filing.

Ms. Jackson further testified that PSO made minor revisions to the language in its Electric Service Rules, Regulations, and Conditions of Service to incorporate updated information related to PSO's digital metering including how to read the advanced digital meters. PSO has also proposed a new facilities rental service agreement for customers requesting equipment beyond standard service.

According to Ms. Jackson, the revenue distribution is the rate design mechanism by which the proposed change in revenue requirement is assigned to the customer classes. The revenue distribution also determines the revenue requirement targets for each rate class in order to design rates that achieve the required revenue.

PSO's revenue distribution proposal follows the revenue distribution recommendation from the Final Order in the most recent rate case, Cause No. PUD201500208, to assign the total revenue requirement change to the retail rate classes. The Order followed the Public Utility Division's recommendation to move all major rate classes to the cost-to-serve each major class without causing major bill impacts. PSO has proposed to move its major retail rate classes to its required cost-to-serve.

Ms. Jackson testified that Table 1 indicates the percentage change in base rates needed to bring each major rate class to an equalized return, the percentage change in base rates proposed by PSO, the proposed total bill change when current fuel and compliance rider revenues are included with the base rate change, and the relative rate of return (RROR) at proposed rates for each major rate class based on the proposed revenue distribution.

Table 1				
Class	Equalized Base Rate Percentage Change	Proposed Base Rate Percentage Change	Total Bill Percentage Change	RROR @ Proposed
Residential	31.01%	31.01%	13.95%	1.00
Commercial & Small Industrial	24.22%	24.16%	9.66%	1.00
Large Power & Light SL3	28.20%	28.17%	9.36%	1.00
Large Power & Light SL2	31.53%	31.53%	9.05%	1.00
Large Power & Light SL1	16.77%	16.64%	4.61%	1.00
Lighting	24.92%	24.86%	15.76%	1.00
Total Retail	28.36%	28.33%	11.43%	1.00

Ms. Jackson further testified that Table 2 shows the present class returns relative to the present retail return on rate base of 3.13 percent, present class returns relative to the proposed rate of return of 7.22 percent, and the proposed class returns relative to the total proposed retail return of 7.22 percent with greater individual class detail.

Table 2			
Class	Present Rates Relative ROR at 3.13%	Present Rates Relative ROR at 7.22%	Proposed Rates Relative ROR at 7.22%
Residential	.94	.39	1.00
LUGS	.96	.66	1.00
General Service	1.14	.44	.99
Power & Light	1.13	.48	1.05
Large Power & Light SL3	.98	.41	1.00
Large Power & Light SL2	.35	.36	1.00
Large Power & Light SL1	1.46	.60	1.00
Municipal Service	3.32	1.44	1.00
Municipal Pumping	1.18	.51	1.01
Lighting	1.52	.64	1.00
Total Retail	1.00	1.00	1.00

Regarding the Ad Valorem Tax Adjustment, Ms. Jackson testified that PSO is requesting that the Final Order in this case recognize the amount of ad valorem tax approved to be recovered through base rates in this case. PSO requests that the Tax Adjustment Rider be modified to include an ad valorem tax adjustment factor that will be adjusted annually to account for an incremental amount of property (ad valorem) taxes expensed above or below the baseline amount included in base rates. In other words, PSO is requesting to trueup the difference between the actual ad valorem taxes recorded on PSO books and records and the actual amount being recovered from customers, annually. The ad valorem tax adjustment will be allocated to customers in the same manner in which ad valorem taxes are currently recovered from customers through their base rates and recovered on a per kWh basis. According to Ms. Jackson, PSO has modified the currently approved Tax Adjustment Rider (TA) to accommodate this proposal. If approved, the factors will be set to zero until the first annual update.

WAYMAN L. SMITH

Mr. Wayman L. Smith, Director, West Transmission Planning for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

According to Mr. Smith, PSO has invested approximately $53.1 million in its transmission system beyond the investment included in the last base rate proceeding. This investment was made to maintain system reliability by replacing failed, aging infrastructure and/or poorly performing equipment, restoring the system following major weather events, upgrading the system in order to meet increasing load requirements and to facilitate new customer connections. The investments for all of these transmission capital projects are necessary and reasonable to ensure PSO's transmission system meets customer demand while adhering to North American Electric Reliability Corporation (NERC), SPP and AEP reliability criterion.

PSO's adjusted test year transmission O&M expenses are approximately $90.7 million including both Non-RTO and RTO expenses. The Non-RTO transmission O&M expenses are necessary and reasonable, and primarily consist of planning, engineering, operating, and maintenance activities performed to support PSO's transmission system. The RTO transmission O&M expenses are necessary and reasonable and consist of those expenses that are allocated to PSO by the SPP RTO for benefits and services received from SPP.

Mr. Smith further testified that the PSO transmission system is managed by the AEP Transmission business unit (AEP Transmission), which utilizes PSO employees, AEPSC employees, and external contractors. AEPSC employees are a shared resource among AEP affiliate companies and allow AEP Transmission to achieve economies of scale, maintain low costs and provide operational efficiencies in managing the PSO transmission system. These AEPSC services to PSO were approximately $5.4 million during the test year. Each of the services provided to PSO by AEP Transmission is necessary for PSO to provide reliable electric service.

According to Mr. Smith, there are over 3,200 circuit miles of transmission lines in the PSO system, stretching from the western Oklahoma border with the Texas panhandle to the eastern Oklahoma border with Arkansas, covering the southern and eastern portion of the state. The voltage levels of the PSO transmission facilities (both overhead and underground) range from 69 kV to 345 kV, as shown in EXHIBIT WLS-1.

PSO has synchronous interconnections with the following transmission owners: SWEPCO, The Empire District Electric Company, Oklahoma Gas & Electric Company (OG&E), Grand River Dam Authority, KAMO Power, Western Farmers Electric Cooperative, Southwestern Power Administration, Associated Electric Cooperative, Inc., Southwestern Public Service Company, Westar Energy, Inc., ITC Great Plains, LLC, OK Transco, Oklahoma Municipal Power Authority and Coffeyville Municipal Light and Power. PSO is also connected asynchronously to the Electric Reliability Council of Texas (ERCOT) by a high-voltage direct current (HVDC) interconnection in north Texas near the Oklaunion generating facility.

Mr. Smith further testified that SPP has functional control of PSO's transmission facilities. PSO purchases regional Network Integration Transmission Service (NITS) under the SPP Open Access Transmission Tariff (SPP Tariff) to serve its retail customers. PSO's transmission system is also used to provide wholesale transmission service under the SPP Tariff to loads served by the other utilities, cooperatives, and municipalities connected to PSO's transmission system. PSO's transmission system also facilitates the delivery of energy under the SPP Integrated Market.

The PSO transmission system is planned, constructed, operated, and maintained through the coordinated efforts of AEP Transmission and SPP. AEP Transmission achieves economies of scale by enabling AEP affiliate companies to share common support staff and resources that help provide cost and operational efficiencies.

Because PSO is interconnected with other companies' transmission systems in Oklahoma and surrounding states, the AEP Transmission organization works closely with SPP and its neighboring utilities to plan and operate the transmission grid. SPP's transmission planning and operational requirements are set out in the SPP Tariff and the SPP Membership Agreement.

Table 1 lists the major transmission projects (over $500,000) that have been added to transmission plant in service since PSO's last rate case. These 11 projects total approximately $36.2 million. Additional projects, each less than $500,000 individually, total approximately $16.9 million to bring the total capital invested during this period to approximately $53.1 million.

Table 1: Transmission Projects Added to Plant in Service Since Last Rate Case

#	Project Description	General Project Category	Total Costs
1	System Improvement Program	Asset Improvement	$9,369,867
2	PSO Storm Recovery	System Restoration	$8,297,643
3	PSO Transmission Telecom Upgrades	Asset Improvement	$5,828,244
4	Asset Replacement and Refurbishment	Asset Improvement	$3,358,710
5	Oneta – Broken Arrow North 138 kV Reconductor	Reliability	$2,866,464
6	Grady Point of Delivery (POD)	Customer Service	$1,692,023
7	Major Equipment Spares	Asset Improvement	$1,109,556
8	Asset Health Monitors - Riverside	Asset Improvement	$1,051,384
9	PSO Vegetation Management Program	Forestry	$1,046,273
10	Lawton Eastside – Lawton 112th & Gore 138 kV Relocation	Customer Service	$908,869
11	Rebuild Carson Substation – Add 4th Transformer	Distribution Driven	$636,857
12	Subtotal of Projects less than $500,000		$16,943,418
	Total		**$53,109,308**

The transmission projects in Table 1 represent: (1) replacement and rehabilitation projects; (2) upgrades required to serve increased customer load, including NERC and SPP reliability compliance requirement projects; (3) customer connections; (4) distribution-driven projects; and (5) storm recovery.

Regarding O&M expenses, Table 2 provides a description of the FERC accounts and the corresponding adjusted test year expenses. Mr. Smith testified that the adjusted test year transmission O&M expenses are approximately $90.7 million. This total includes transmission O&M expenses for both Non-RTO and RTO accounts.

Table 2 – Adjusted Test Year Expenses by FERC Account

FERC Account	FERC Account Description	O&M Expense	[illegible]	[illegible]
560	Oper Supervision & Engineering	$3,752,798	($978,060)	$2,774,738
561*	Load Dispatch, Reliability, Plng & Stds Develop, Transmission Service Studies	$2,753,756	$5,746	$2,759,502
562	Station Expenses – Nonassoc	$456,387	($3,610)	$452,777
563	Overhead Line Expenses	$254,824	($5,245)	$249,580
566	Misc Transmission Expenses, SPP FERC Assessment Fees, R.King Trans Cnter Exp – Affil	$3,717,283	($539,283)	$3,178,000
567	Rents – Nonassociated & Associated	$5,399	$0	$5,399
568	Maint Supv & Engineering	$155,935	($5,790)	$150,146
569	Maintenance of Structures, Computer Hardware & Software, & Communication Equip	$1,082,116	($417)	$1,081,699
570	Maint of Station Equipment	$2,407,756	$24,480	$2,432,236
571	Maintenance of Overhead Lines	$3,175,160	$1,433,862	$4,609,022
572	Maint of Underground Lines	$100	($96)	$4
573	Maint of Misc Transmission Plt	$231,481	($39,098)	$192,383
Non RTO Accounts	**Subtotal**	**$17,992,995**	**($107,510)**	**$17,885,485**
561**	Scheduling, System Control & Dispatching Svcs, Reliability, Plng & Stds Develop	$11,282,474	$1,392,551	$12,675,025
565	Trans of Electricity for Others	$85,563,032	($26,741,607)	$58,821,425
575	Regional Market Expenses	$1,229,619	$106,170	$1,335,789
RTO Accounts	**Subtotal**	**$98,075,125**	**($25,242,886)**	**$72,832,239**
	Total	**$116,068,120**	**($25,350,395)**	**$90,717,724**

*includes FERC Accounts 561.1, 561.2, 561.3, 561.5, 561.6

**includes FERC Accounts 561.4, 561.8

Mr. Smith further testified that SPP works with its members to determine and construct the transmission infrastructure needed in the near- and long-term planning horizon to maintain electric reliability, meet public policy mandates and provide economic benefits. SPP does not own or build transmission assets. The SPP Tariff and governing documents contain the rules that govern transmission construction by SPP Transmission Owning members. SPP's transmission planning services include the development of regional transmission expansion plans, oversight of transmission upgrade construction in accordance with approved plans, and development and implementation of cost allocation methodologies to ensure appropriate recovery by the constructing SPP Transmission Owners (TOs). SPP's construction oversight includes monitoring project status and costs through quarterly reporting by the constructing TOs and ensuring proper adherence to cost estimates and construction in-service need dates.

According to Mr. Smith, the SPP transmission expansion plan (STEP) is a compilation of SPP-directed projects based on studies performed by SPP to determine upgrades needed to maintain reliability, provide transmission service, provide for generation interconnections, and provide economic benefit to its Members into the future. SPP's transmission planning processes seek to identify system limitations and needs, develop cost-effective transmission solutions, and ensure timely completion of needed system expansion within reasonable cost expectations. Rather than looking at the needs of just one load serving entity (LSE), SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefits to the region.

Mr. Smith further testified PSO, as an LSE taking regional network integration transmission service under the SPP Tariff, is responsible for its load share of the revenue requirement associated with infrastructure investment in the greater region of SPP's transmission system, and thus, the charges for which PSO is responsible are not fully controllable by the Company. However, those costs are reasonable to maintain and provide reliable transmission service in the greater region of the SPP transmission system.

Mr. Smith testified regarding the benefits to customers from building transmission facilities. Strengthening SPP's transmission infrastructure addresses SPP's transmission service customer needs to provide reliable transmission service to all customers. A strong transmission infrastructure helps to relieve the transmission constraints identified in SPP's generation interconnection queue to bring additional generation on line to provide additional energy sources. The SPP RTO planning processes under the SPP Tariff provide the means for LSE's (including PSO), generators that require interconnection and other parties needing transmission services to obtain these transmission services from the SPP.

Mr. Smith further testified that when storms devastate an electric system, such as ice storms or tornadoes, the transmission system must be robust enough to provide service to customers in other areas of the system. While the damage may be severe to specific portions of the transmission system, the transmission system is designed to be diverted around the damaged facilities to continue to reliably serve load in areas not geographically near the storm-damaged facilities. Natural disasters can cause major damage to the electrical grid but these types of outages confirm the need for investment in both transmission and distribution to reliably serve load. The combination of a robust transmission and distribution system provides a public benefit in increased reliability to customers.

As new transmission lines are put in service, more paths become available for energy to flow to loads. This benefits customers by enhancing reliability through new transmission paths, keeping their lights on in times of system stress.

According to Mr. Smith, there exists a public need for an improved robust electric transmission system that can deliver lower-cost energy to customers. Investment in needed transmission infrastructure to accommodate the flexibility in the transmission system to provide access to generation with lower cost-energy provides a public benefit.

ANDREW R. CARLIN

Mr. Andrew R. Carlin, Director of Compensation & Executive Benefits for American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Carlin testified that the employee compensation that PSO seeks to include in its cost of service for rate making purposes is reasonable, appropriate and beneficial to PSO customers. The inclusion of incentive compensation in a utility's cost of service for rate making purposes should be based on whether the total compensation provided to employees is reasonable and market-competitive unless such compensation is inefficient, improvident or imprudent.

Mr. Carlin compared PSO's compensation levels and practices to market compensation levels using third-party compensation surveys to determine a market-competitive range centered on the market median for similar positions as a check on reasonableness. According to Mr. Carlin, that comparison shows that PSO's average target total compensation for physical and craft positions is 6.4% percent below the market median. If PSO's annual incentive compensation were to be excluded, then total compensation for six of the 10 physical and craft positions (60.0 percent) would fall below the market-competitive range and PSO's average total compensation would fall to 10.8 percent below the market median, which is below the +/- 10 percent the competitive range for these positions. The comparison also shows that the PSO's target total compensation for non-executive exempt positions was below the market median but within a +/- 15 percent market-competitive range. According to Mr. Carlin, if the Company's annual incentive compensation were to be excluded, then total compensation for these positions would fall to 10.2 percent below the market median, which is within but at the low end of the market competitive range. However, 3 of 22 individual positions (13.6 percent) would fall below the market competitive range. Thus, the annual incentive compensation paid by PSO, or a similar amount of additional base pay, is necessary to maintain the competitiveness of PSO's compensation for these positions.

Mr. Carlin evaluated AEP's management and executive positions total direct compensation (TDC) to a third-party compensation study. The peer group used for this study consists of similarly-sized utility companies that represent the talent markets from which AEP must compete to attract and retain management and executive employees. An analysis of this study shows that target TDC for the 17 executive positions whose time and expense is generally allocated to PSO were within the +/- 15 percent market competitive range on average as of July 1, 2016. However, AEP's total compensation would be below the market-competitive range for 100 percent of these executive positions without either the annual incentive compensation or the long-term compensation portion of total compensation, unless it was replaced with additional base salary.

Mr. Carlin testified that the inclusion of a financial component in annual incentive compensation plans is prevalent throughout the utility industry. Other state commissions have approved the inclusion of annual and long-term incentive compensation in utility rates. The Commission has also approved inclusion of long-term incentive compensation because "the interests of the Company's shareholders and its customers were substantially aligned." Nearly all public utility companies of AEP's size and complexity have similar long-term incentive compensation, as do nearly all public general industry companies.

Mr. Carlin testified that the total value of compensation that the Company provides is within the market-competitive range required to attract and retain the suitably knowledgeable, experienced and qualified employees the Company needs to safely, efficiently and effectively provide reliable electric services to customers. The annual and long-term incentive compensation is designed to effectively control overall expenses, which reduces the cost of service to customers. The compensation paid to employees, including its variable annual and long-term incentive components, is a reasonable, necessary and prudent cost of providing service to customers according to Mr. Carlin.

Mr. Carlin testified that all of the Company's employees, except temporary positions, participate in annual incentive compensation. Accordingly, all employees, from Customer Service Representatives in the Customer Operations Center, to lineman, to generation plant personnel have an incentive compensation opportunity that links incentive compensation to performance measures. The majority of the annual incentive compensation goals for the PSO employees are measured at the operating company (PSO) level. The performance measures and communications are fully described in written documents for major business units and other groups within the organization.

For the test year there were separate performance measures for PSO (distribution and staff functions), Customer & Distribution Services, Generation, Transmission and other smaller groups. The PSO annual incentive compensation component used a balanced scorecard consisting of three categories of performance objectives: Infrastructure Development (25%), Customer Experience (40%) and Employee Experience (35%).

Mr. Carlin further testified that the various non-financial, operational measures (i.e., reliability, regulatory pursuit of customer-driven programs, customer satisfaction, economic development, efficiency and effectiveness, risk mitigation, customer experience, emergency restoration planning, employee culture and safety) benefit customers by promoting reliable, efficient and safe operations. The financial measures benefit customers by promoting the optimal use of the Company's limited financial resources, leading to operations and maintenance (O&M) and capital cost control, and contributing to the financial health of the Company, all of which benefits both customers and shareholders alike through the more reasonable O&M and capital expenditure levels that are achieved. Customers directly benefit from incentive measures designed to ensure fiscal discipline. Efficient use of the Company's limited resources results in more work being done for the same cost and, ultimately, a lower cost of service. Operational measures improve the Company's ability to meet customers' service expectations while financial measures help effectively control O&M and capital expenditures. These types of measures work together to better meet customers' cost and service expectations as well as shareholders' financial expectations.

According to Mr. Carlin, customers' interests are furthered when PSO provides service as effectively and efficiently as possible, and this is often best measured from a financial perspective. The achievement of financial goals also helps ensure that PSO earns a reasonable rate of return based on the return on equity (ROE) established through the rate cases, which reduces the frequency of rate case filings and provides more funds for infrastructure investment. A financially-strong company has better access to capital, particularly during recessionary times, and a lower cost of capital, which in turn benefits customers through a lower cost structure and lower rates.

Mr. Carlin testified that Long-term incentive compensation provides the same benefits as annual incentive compensation with the primary benefit being that, as a critical component of a reasonable and market-competitive compensation package, it allows the Company to attract and retain the employees needed to efficiently and effectively provide services to customers. Long-term incentive compensation also benefits customers by linking compensation to longer-term performance, which encourages participants to take a longer-term perspective in their decision making and promotes management continuity. Taken together, the annual and long-term incentives measures balance the short-term and long-term interests of the Company and its customers. PSO is requesting that the test year target amount of long-term compensation be included in PSO's cost of service.

David J. Wathen

Mr. David J. Wathen, Director, Southeast Rewards Practice Leader for Willis Towers Watson, testified on behalf of PSO.

Mr. Wathen testified that Willis Towers Watson reviewed the competitiveness of PSO's compensation philosophy and annual and long-term incentive compensation plan designs. The purpose of the assessment was to compare PSO's compensation philosophy and incentive plan designs to the market practices of comparably-sized, regulated utilities.

Mr. Wathen further testified that to assess the competitiveness of PSO's plan designs relative to market practice, Willis Towers Watson's primary market data sources were current proxy disclosures for the Large and Small Utility Peer Groups. The Large Utility Peer Group consisted of 18 publicly-traded, regulated utilities with revenues in a range of approximately ½ to 2-times AEP revenues. Given comparably-sized subsidiary utilities like PSO do not typically disclose their annual incentive compensation plan design practices, Willis Towers Watson examined a peer group of 13 publicly-traded, regulated utilities with revenues in a range of approximately ½ to 2-times PSO revenues.

Like PSO, all of the Large and Small Utility Peer companies examined have an annual incentive compensation plan to provide a market competitive pay mix that enables them to attract, retain and motivate the critical talent needed to successfully run the company. While specific incentive design elements of annual incentive plans may vary among utility peers, PSO's plan design differences are limited. Overall, the analysis indicates PSO's annual incentive compensation plan design is comparable to and competitive with the incentive plan designs of utility peers. Mr. Wathen testified that PSO's annual incentive plan design places a greater weighting (90% in total) on operational measures than financial measures (only 10%). The 90%

operational weighting, which includes operational metrics divided between infrastructure development, customer experience, and employee experience, is significantly greater than the average of other utility operating company incentive plan designs reviewed. This plan design difference is intentional as PSO wanted to emphasize the operational goals and place greater emphasis on measures that aligned with customers and that employees had greater direct ability to influence.

Mr. Wathen further testified that Willis Towers Watson reviewed the competitiveness of PSO's long-term incentive compensation plan design. The purpose of the assessment was to compare the design of PSO's long-term incentive compensation plan and its various design elements to market practice.

Mr. Wathen testified that the same Large and Small Utility Peer Groups used for assessing the competitiveness of PSO's annual incentive compensation plan design were used to assess the competitiveness of PSO's long-term incentive compensation plan design. Overall, the assessment indicates PSO's long-term incentive plan design is comparable to and competitive with designs of utility peers. Like PSO, every utility examined has a long-term incentive compensation plan which is used to help attract, retain and motivate key employees. As with annual incentive plans, companies design their long-term incentive plans to align with their business strategies and circumstances, so plan design practices will vary among utility peers, but PSO's long-term incentive compensation plan design falls within the range of market practices for the utilities examined

Mr. Wathen testified that Willis Tower Watson's overall assessment indicates that the compensation philosophy and design of the annual and long-term incentive compensation plans at PSO are comparable to designs of utility peers. Given the markets where PSO competes for talent, it is essential for the company to provide competitive compensation programs in order to attract, retain and motivate the critical talent needed to successfully run the company, which enables PSO to provide the service customers expect at a reasonable cost. Mr. Wathen testified that based on his experience working with other utilities and general industry companies, as well as the results of the study, he finds the compensation philosophy and incentive plan designs at PSO are reasonable and well within competitive market norms.

According to Mr. Wathen, the inclusion of incentive compensation plans, reflecting both annual and long-term focused plans, is an essential part of a market competitive pay mix. All of the companies in the Large and Small Utility Peer Groups have annual and long-term incentive compensation plans in place. To attract, retain and motivate talent needed to successfully run the company, PSO needs to provide a market competitive compensation program, which includes both annual and long-term incentive compensation plans.

Mr. Wathen testified that utilities like PSO maintain annual and long-term incentive compensation plans in order to award plan participants for achievement of pre-defined performance goals. Pay is "at-risk" in that no award will be paid if the defined threshold levels of performance are not achieved, but awards can also be earned for achieving outstanding performance.

According to Mr. Wathen, a key benefit of PSO's use of annual and long-term incentive compensation plans is that they align with competitive market practice and thereby enable PSO to compete in the market for talent. A shift to an all base salary program for PSO could have unintended consequences. If all or part of the annual and/or long-term incentive compensation at PSO were eliminated, the Company would likely be forced to increase fixed pay (i.e., base salary) to above market competitive levels in order to attract and retain talent. This would be counter to the pay-for-performance approach PSO currently employs, which is to put annual and long-term compensation "at-risk". Incentive compensation plans allow PSO to differentiate pay based on performance and allocate compensation to the highest performing and most deserving employees.

PAULINE M. AHERN

Pauline M. Ahern, Executive Director with ScottMadden, Inc., testified on behalf of PSO.

Ms. Ahern testified that under traditional utility ratemaking, a utility is provided an opportunity to earn a fair and reasonable rate of return on its investment used and useful in the provision of utility service in exchange for its commitment to provide service to customers within its authorized service territory. This concept is sometimes referred to as the regulatory compact. Public utility rates, as typically established throughout the United States, should provide the utility recovery of all prudently incurred costs, including an opportunity to earn a fair rate of return.

Ms. Ahern testified that the fair rate of return standard is a legal concept, established many years ago in Bluefield and Hope, having informed the rate of return decision making of regulatory commissions throughout the U.S. for nearly 100 years. According to Ms. Ahern, the standards of fair rate of return established such a return is: 1) sufficient to ensure a utility's financial integrity; 2) adequate to enable the utility to attract capital at reasonable terms; and, 3) commensurate with returns on investments in enterprises having corresponding risks, with the "enterprises having corresponding risks" are not being limited to regulated utilities. The fair rate of return has become defined in regulatory ratemaking as the cost of capital, both of debt and equity and is based upon the economic principle of "opportunity cost", which is the implied cost of foregone alternative investment opportunities.

According to Ms. Ahern, the consequence of the Oklahoma Corporation Commission's ("OCC") decision in this proceeding, therefore, should provide PSO the opportunity to earn a return, including a cost of common equity, that is: 1) sufficient to ensure its financial integrity; 2) adequate to attract capital at reasonable terms; and, 3) commensurate with returns on investments in enterprises having corresponding risks. To the extent that PSO is provided a reasonable opportunity to earn its market-based cost of common equity, neither customers nor its shareholder should be disadvantaged.

Ms. Ahern further testified that the relationship between risk and return can be demonstrated and quantified by observing the differences in bond yields for various bond ratings categories. Both Moody's and Standard & Poor's (S&P), two major bond rating agencies, assign bond/credit ratings in various ratings categories, each of which distinguishes a different level of risk. Both credit rating agencies denote increasing credit risk with Aaa / AAA being the least risky and C being the riskiest.

Ms. Ahern testified that quantification of the effect of risk can be demonstrated by the spreads between Moody's bond yields for various bond rating categories as shown on her EXHIBIT PMA-3. On average over the period of January 2007 through April 2017, Aa corporate bonds yielded 24 basis points (0.24%) more than Aaa corporate bonds because the Aa bond rating category indicates greater risk than the Aaa bond rating category. Likewise, A rated public utility bonds yields 24 basis points (0.24%) greater than the less risky Aa bond rating category and Baa rated public utility bonds yielded 55 basis points (0.55%) more than the less risky A bond rating category.

In view of the foregoing, the greater the perceived risk of an investment, such as a stock or debt investment in an investor-owned public utility, the greater the investor required return consistent with the financial principle of risk and return. Hence, the cost rate of common equity for public utilities perceived by investors to have greater investment risk will be greater than for those public utilities which are perceived by investors to have lower investment risk.

Ms. Ahern further testified that the investor-required return on common equity reflects investors' assessment of the total investment risk (business and financial) of the subject firm. Business risk reflects the uncertainty associated with owning a company's common stock without consideration of the company's use of debt and/or preferred financing. Financial risk is the incremental uncertainty in the expected earned return once senior capital, debt and preferred stock, are issued.

Examples of the business risks generally faced by utilities include, but are not limited to the following: the regulatory environment, including but not limited to the level of the allowed returns on common equity, the potential that operating expenses, depreciation expense and capital expenditures may be disallowed within a regulatory jurisdiction; environmental requirements; customer mix and concentration of customers; service territory economic growth; market demand; uncertainties of supply; operations; capital intensity; size; the degree of operating leverage; and, the like, all of which have a direct bearing on earnings. As a practical matter, business risk factors are inter-related and are not wholly distinct from one another. Therefore, it is difficult, if not impossible, to specifically and numerically quantify the effect of any individual factor on the investor required return, i.e. the cost of capital. In determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent that investors view a company as being exposed to additional risk as compared to its peers, their required return will increase and vice versa.

For regulated utilities, business risks are both long- and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability for investors to recover the return on and return of their capital. Utility service is capital intensive. Because utilities accept the obligation to provide safe and reliable service at all times in exchange for the opportunity to earn a fair return on their investment, they generally do not have the option to delay, defer, or reject capital investments. Therefore, utilities generally do not have the option to avoid raising needed external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks, such as changes in environmental law and disruptive technologies, are of considerable concern to equity investors. That is, the risk of not recovering the return on and return of their investment extends far into the future. But, the timing and nature of events that may lead to losses are also uncertain.

Ms. Ahern testified that financial risk is created by the introduction of senior capital, i.e. debt and/or preferred stock, into the capital structure. It is the additional risk that a company may not have sufficient cash flows to meet its financial obligations. The higher the proportion of senior capital in the capital structure, the higher the financial risk that must be factored into the common equity cost rate because, consistent with the basic financial principle of risk and return, investors demand a higher common equity return as compensation for bearing the higher investment risk incurred due to the use of debt and/or preferred stock.

Ms. Ahern testified that in simple terms, the cost of common equity represents a bond yield plus a risk premium over a bond yield to compensate for the additional risk associated with ownership of equity. Given that corporate, including public utility, bond yields are a function of bond/credit ratings, the opinions of credit rating agencies, such as Moody's and S&P, and the bond/credit ratings they assign, are critical to the cost of capital, both debt and equity, for regulated and non-regulated firms alike. To reiterate, the credit rating agencies base their opinions on a comprehensive analysis of both business and financial risk.

According to Ms. Ahern, Moody's identifies and weights four key factors in its electric and gas utility methodology below:

TABLE 1
Regulated Electric and Gas Utility Rating Methodology
KEY RATING FACTORS AND WEIGHTINGS

1.	**Regulatory Framework (25% weighting)**
2.	**Ability to Recover Costs and Earn Returns (25 % weighting)**
3.	**Diversification (10% weighting)**
4.	**Financial Strength and Liquidity (40% weighting)**

The regulatory framework in which a utility operates and the ability granted to that utility to recover its costs and earn its allowed return, is given 50% weight by Moody's when determining the credit quality of that utility. Moody's states:

The framework in which a regulated utility operates is typically one of its most significant credit considerations. The regulatory structure and its general framework is a primary consideration that differentiates the industry from most other corporate sectors.

* * *

> In evaluating a utility's regulatory framework, we consider such things as the regulatory body's independence; its legislative or political environment; the extent of the regulatory frameworks' development; its track record for predictable, stable decisions; the utility's business model;

> and the openness of the regulators to alternative rate mechanisms that tend to provide additional assurance of timely cost recovery and the ability to earn a return on invested capital. (emphasis added)

Ms. Ahern further testified that S&P's Key Credit Factors For the Regulated Utilities Industry also considers regulatory climate to be critical to the bond/credit rating process, so critical that S&P has devoted approximately four (4) pages, pages 6 – 9, in Key Factors to a description of how S&P assesses regulatory advantage, in contrast to approximately one and one-half (1 ½) pages, pages 18 – 19, to cash flow and leverage analysis. S&P states:

> The regulatory framework/regimes' influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has significant bearing on a utility's financial performance.

S&P lists several factors of regulatory climate which is considers in its analysis, including:

1. Transparency of the key components of the rate setting and how these are assessed;
2. Predictability that lowers uncertainty for the utility and its stakeholders;
3. Consistency in the regulatory framework over time;
4. Recoverability of all operating and capital costs in full;
5. Timeliness of cost recovery to avoid cash flow volatility; and,
6. Attractiveness of the framework to attract long-term capital.

It is clear then, that, in addition to the regulatory environment in which a utility operates, being granted the opportunity to earn its authorized rate of return and to recover prudently incurred costs, i.e. O&M, depreciation, etc. are of significant importance in the bond/credit rating process.

Ms. Ahern testified that if PSO's prudently incurred O&M expenses are not allowed to be recovered in rates, there will be a shortfall in the Company's bottom line, i.e. earnings or net income, as well as a negative impact on cash flows, which may inhibit PSO from earning its allowed cost of capital, which, in turn, will affect investors perception of PSO's risk, having a direct impact on its cost of capital (debt and equity), i.e. the investor required return.

Likewise, if PSO is not allowed a sufficient and prudently incurred level of depreciation expense, its cash flows and credit metrics will be negatively affected, which also affects investor (both debt and equity) perception of risk, as it may result in a bond/credit rating downgrade from the credit ratings agencies, i.e. Moody's and S&P, which, in turn, will also increase investor perception of risk, raising both PSO's cost of debt and cost of common equity.

Similarly, if prudently incurred costs such as those associated with utility plant removed from service before the investment is fully recovered, or "stranded", are not allowed to be recovered, PSO's cash flows may be impaired which also affects investors' perception of risk according to Ms. Ahern.

Regarding incentive compensation, Ms. Ahern testified that in today's business and economic environment, incentive compensation, both short-term and long-term, are standard practice and necessary to attract and retain qualified employees for both regulated utilities and non-regulated competitive firms alike.

PSO's short-term, i.e. annual, incentive compensation is based upon defined performance objectives related to containing O&M expenses, efficient capital budgeting, net income levels, reliability, reducing Commission complaints, improving customer satisfaction, process improvements, OSHA compliance, and safety measures. PSO's long-term incentive compensation is aimed at improving PSO's long-term financial performance through long-term cost control and fiscal responsibility. Ms. Ahern testified, a firm's financial performance affects its credit quality and hence cost of capital. Improved financial health leads to improved credit quality, lower debt and equity costs and ultimately lower rates for regulated utilities.

Such incentive compensation, both short- and long-term, therefore, benefits customers through continued safe, reliable and efficient service at affordable rates. Therefore, such costs, in her opinion, are prudent and should be recovered in rates.

Ms. Ahern testified that Northeastern Unit 4 costs should be recovered through rates because it is in the best interest of all stakeholders-- customers, and shareholders alike. Both recovery on (i.e. a return) and recovery of (i.e. depreciation) PSO's investment in the Northeastern Unit 4 should be allowed by the Commission because PSO's initial investment in the Northeastern Unit 4 was deemed prudent at the time the utility plant was placed into service. In addition, PSO's requested cost of common equity does not currently account for the increased regulatory risk associated with a change from recovery of both the cost of the Northeastern Unit 4 and the return on such investment that investors expect. If the recovery on and of PSO's investment in the Northeastern Unit 4 is not allowed, PSO's credit quality would likely be negatively affected and regulatory risk in Oklahoma would likely increase, leading to both possible bond/credit downgrades and an increase in PSO's cost of capital (debt and equity), resulting in a higher revenue requirement and higher customer rates.

Ms. Ahern testified that S&P stated that, related to the closing of coal-fired generation plant due to environmental compliance, such as PSO's Northeastern Unit 4:

> Another way to recoup costs is to recover the remaining book value of the unit plus a return on this remaining value. This can include both ongoing recovery through base rates of the remaining depreciation on the plant and earning a rate of return on this remaining asset value. . . The quicker they recover these costs, the stronger the cash flow support and cash flow coverage measures.

Relative to the inability of a utility with no recovery options, S&P states the following:

Some utilities may not yet have options to recover the remaining book value of coal plants that retire early. In this scenario, the utility would likely write off the asset without recovering operating cash flow. The loss of depreciation and a return on the asset base from rates would lower operating cash flows, and resulting cash flow financial measures. (emphasis added)

Specifically related to PSO, according to Ms. Ahern, Moody's stated a credit challenge facing PSO was that regulatory support is needed to recover sizeable capital investment for environmental controls and system reliability. In Ms. Ahern's opinion, the remaining costs associated with PSO's investment in Northeastern Unit 4 are part of the costs referenced by S&P, when it identified three (3) factors which could lead to a downgrading of PSO's bond/credit rating:

1. If the regulatory environment took on an adversarial tone;
2. If there were to be a significant increase in capital or operating expenditures that were not able to be recovered on a timely basis; and,
3. If key financial credit metrics exhibited a sustained deterioration over a period of time including interest coverage below 4.5x or CFO pre-WC to debt remaining below 19%.

Ms. Ahern discussed how the returns of regulated utilities, such as PSO, compared to non-regulated firms of similar risk such as Kimberly-Clark and WalMart. According to Ms. Ahern, since the return on common equity set in this proceeding will be applied to the book value common equity portion of PSO's rate base, it is reasonable to also look to the projected returns on book common equity of non-price regulated firms such as the companies in the Non-Regulated Sample, because not only do utilities, such as PSO, compete with other utilities for capital, they compete with non-price regulated firms as well. As summarized in Table 1 Value Line projected the Non-Regulated Sample to earn an average return on book common equity of 26.6% for 2020-2022. In contrast, the Electric Sample is expected to earn an average return on book common equity of 11.1%. In her opinion, the difference between the projected returns for the two samples is due to the fact that returns on book common equity for utilities, such as the Electric Sample, face downward pressure because they are a function of regulatory allowed returns on common equity with competitive firms not facing such downward pressure.

To derive the historical market returns of the Electric Sample and Non-Regulated sample, Ms. Ahern calculated monthly market returns for each company from January 2012 through April 2017. She then calculated the market-value weighted average monthly returns for the Electric Sample and the Non-Regulated Sample. The volatility of these average monthly returns from January 2012 through April 2017, as measured by both the standard deviation of the monthly returns and the coefficient of variation ("COV"), are summarized in Table 2 below and detailed on page 1 of EXHIBIT PMA-11. Since the standard deviations and COVs of the two samples are similar, the two sample groups exhibit similar return volatility, i.e. risk, over the period. Thus, not only is the Non-Regulated Sample similar in total risk, i.e. systematic plus non-systematic risk to the Electric Sample, the riskiness of its market returns as measured by the COV are similar to that of the Electric Sample as well.

Table 2: Volatility of the Market Returns of the Electric Sample and the Non-Regulated Sample

	Electric Sample	Non-Regulated Sample
Standard Deviation	3.88%	2.96%
Coefficient of Variation (COV)	3.1040	2.8462

Ms. Ahern testified that the comparable earnings of non-price regulated firms, whether market returns or earned book returns, comparable in total risk to a group of utility firms, is derived from the "corresponding risk" standard of the landmark U.S. Supreme Court cases Hope and Bluefield. Therefore, it is consistent with the Hope doctrine that the return to the equity investor should be commensurate with returns on investments in other firms having corresponding risks based upon the fundamental economic concept of opportunity cost which maintains that the true cost of an investment is equal to the cost of the best available alternative use of the funds to be invested. Utilities must compete for capital with both regulated and non-regulated firms. Therefore, the opportunity cost principle applies to both regulated and non-regulated firms as well consistent with one of the fundamental principles upon which regulation rests: that regulation is intended to act as a surrogate for competition and to provide a fair rate of return to investors.

Examining the returns of both regulated and non-regulated companies, provides regulators with some assurance that the allowed return is not excessive while at the same time providing a reasonable opportunity for the regulated utility to be able to obtain capital at reasonable costs.

C. Richard Ross

C. Richard Ross, currently the Director RTO Policy SPP/ERCOT for American Electric Power Service Corporation (AEPSC), testified on behalf of PSO.

Mr. Ross testified that PSO is a member of the SPP, a FERC-approved Regional Transmission Organization (RTO). SPP's members include investor-owned utilities, municipal systems, generation and transmission cooperatives, state agencies, independent power producers, power marketers and independent transmission companies. The SPP RTO's operations are guided by numerous stakeholder-populated committees, working groups and task forces that maintain and develop policies to be implemented by SPP. Included in these stakeholder groups is the Regional State Committee (RSC), comprised of participating state regulators across the SPP footprint, and the Cost Allocation Working Group (CAWG), which is made up of staff members of those state regulatory authorities. The OCC is represented on both the RSC and CAWG. Additionally, PSO staff or AEP staff representing PSO are active and have membership roles in almost all of the SPP Committees and Working Groups. The Company's goal through active participation in the stakeholder process, and in particular the Integrated Transmission

Planning (ITP) process, is to provide assurance that the projects selected for construction by SPP represent the lowest reasonable cost solutions to resolve issues on the grid.

Mr. Ross further testified that the services provided by SPP and procured by PSO under the OATT tariff fall into three main categories: administrative services, market and ancillary services, and transmission services. The transmission services are those services necessary to reserve services from points of receipt, such as one of PSO's generating resources, to points of delivery, such as PSO's retail customers. These services are provided under Schedules 7, 8, 9, 10 and 11 of the OATT tariff. The majority of PSO's expenses in this category are under Schedules 9 and 11 and result from the regional Network Transmission Service provided by SPP to PSO. The Schedule 9 expenses are mostly associated with the transmission facilities originally placed in service prior to the implementation of the regional funding elements of the SPP OATT tariff, including any of those facilities rebuilt to maintain their reliable operation. The Schedule 11 charges are associated with the construction, maintenance and operation of those facilities ordered by SPP through its planning procedures outlined in Attachment O of the tariff.

According to Mr. Ross, SPP provides services on a regionalized, cost-efficient basis, with FERC oversight over the rates SPP charges its customers. Through the numerous stakeholder committees and working groups, which include participation by PSO and representatives from various state regulatory commissions, additional oversight exists to help ensure PSO (and its customers) pay the lowest reasonable costs for the services it procures from the SPP.

According to Mr. Ross, there are several steps that he believed assured the costs paid by PSO are reasonable.

First, the nature of the ITP process establishes a process under which the most cost-effective solutions are identified to resolve reliability issues and provide economic benefits to the region. This first step is critical, and perhaps most important according to Mr. Ross, in that a transmission project that is built on time and at a very low cost is of little consequence if there were a different and better project alternative. Due to the iterative and open nature of this ITP process, projects are reviewed multiple times by the stakeholders, customers, and interested parties. Mr. Ross further testified that it should be noted that by the time a project reaches the Board for approval, the project has been repeatedly reviewed by transmission owners, state regulatory agency staff, transmission service customers, and other interested parties, including the RSC. It is this rigorous and open review that assures SPP, its members and its customers that the most cost-effective projects are being selected for construction. He believed AEP's active participation in the SPP stakeholder process and in particular the ITP planning process provides the assurance that the projects selected for construction by SPP represent the lowest reasonable cost solutions to resolve issues on the grid.

Second, once selected it is important that the cost of these projects remains reasonable. SPP continuously monitors and produces quarterly construction tracking reports which allow it, as well as other stakeholders, to monitor the progress on particular projects. Project tracking is designed to provide a transparent process for the tracking of costs as the project progresses toward completion. Certain projects that deviate substantially from the baseline cost estimate, as described in the SPP business practices, will be referred to the SPP Project Cost Working Group (PCWG) for further review.

Mr. Ross further testified that the rates charged by SPP to customers are under the oversight of the FERC. In some instances, Transmission Owners have a stated rate established in their last FERC-approved rate case. However, in most cases Transmission Owners have received approval from FERC for a formula-based rate, which is revised on an annual basis. These formula-based rates include annual reporting and update procedures, which provide an additional opportunity for cost review. Schedule 11 charges may not be changed absent a filing with FERC.

Mr. Ross stated that AEP and PSO have chosen to focus the bulk of their monitoring efforts in active participation within the SPP stakeholder groups. With 30 Transmission Owners in the SPP, Mr. Ross beleived participation in the SPP process is a more reasonable and effective way to protect our interests and those of our customers, although we would not hesitate to file a complaint with FERC if we deemed a particular charge to be unreasonable.

Mr. Ross explained the benefits PSO Oklahoma customers had received with the expansion of the transmission system by SPP. According to Mr. Ross, PSO's customers benefit in many ways from this regional expansion of the transmission system. Although there are others, there are two areas where the benefits to PSO's customers are more direct and apparent. The first are the changes that have taken place over time as AEP has requested new transmission services from SPP on behalf of PSO's customers. The expansion of the transmission system has increased the likelihood that new transmission service requests are possible without additional upgrades to the system being necessary. The second is the change in the dispatch of the PSO generation fleet that has been made possible through the expansion of the transmission system, and the SPP-administered market functions. These contribute to PSO's efforts to operate its generating fleet, make energy purchases and make energy sales to meet the needs of PSO's customers at the lowest reasonable cost.

THOMAS J. MEEHAN

Mr. Thomas J. Meehan, Senior Vice President, and Project Director with Sargent & Lundy LLC (S&L), testified on behalf of PSO.

Mr. Meehan testified that his testimony addressed the results of the site-specific studies conducted by S&L to estimate the costs of dismantling PSO's electric power generating facilities. These studies detail the estimates to dismantle the following PSO generating facilities:

Southwestern Plant Units 1-5
Northeastern Plant Units 1-4
Oklaunion Plant Unit 1
Weleetka Plant Units 4-6
Riverside Plant Units 1-4
Comanche Plant Unit 1
Tulsa Plant Units 2-4

Mr. Meehan testified that his testimony described the update to the PSO electric generating facility demolition cost estimates that were prepared by S&L in 2015 in order to capture any changes that may have occurred at the PSO facilities between 2015 and 2017 that would affect the demolition costs. The demolition techniques and crew mixes assumed in the S&L cost estimates are efficient and cost effective. According to Mr. Meehan, they are typical demolition techniques that are used in the industry and are comparable to techniques used by major demolition contractors who have competitively bid and successfully executed the subject work for many years. The study assumes that it would not be necessary to remove the tens of thousands of feet of underground piping and wiring from the sites (i.e., this is not a "brick by brick" cost estimate, which assumes every single component is dismantled in an inefficient manner). The estimate of the cost to dismantle each specific generating station includes an estimated positive salvage value for certain materials. These assumptions minimize the dismantling cost estimate and result in a very reasonable cost estimate for dismantling the facility. The assumptions and methods used to prepare these estimates were consistent with prudent industry practices and previous S&L demolition estimates.

According to Mr. Meehan, the demolition cost estimates for PSO's electric power generating facilities total approximately $167 million. Changes in labor rates and the market value of scrap copper and steel were the primary reasons for the differences in estimated demolition costs from the 2015 study.

According to Mr. Meehan, electric utilities request S&L to prepare demolition cost estimate studies for budgeting purposes and to use in their depreciation studies.

Mr. Meehan further testified that it was necessary to dismantle a generation station at the end of its useful life for a number of reasons. To reuse land, structures and facilities would need to be removed. Since the number of locations in the nation that are conducive to electric generating stations is limited, it is possible that after the retirement of the units, future generating stations would be located at these sites to take advantage of existing substations, transmission lines, gas lines, rail lines, etc. Reuse of these locations would require removal of any previous structures. Also, there is a safety concern, and therefore a potential public risk, if security is not maintained at the facilities. If abandoned structures are not dismantled, the structures will deteriorate if not maintained. Some of the structures, such as exhaust stacks, could create potential public safety risks and have the potential to collapse and cause damage. Removal and disposal of asbestos is also required in any location where it exists.

According to Mr. Meehan, partially demolished abandoned facilities may have hazardous contents and pose a safety hazard to individuals that enter the area. Site grading is an important final step to restoring the site to a more natural storm drainage condition that will not result in random pooling of water or erosive drainage conditions such as gullies and washouts that may be transferred to adjacent properties.

Mr. Meehan testified that S&L provided an update to existing PSO electric generating facility demolition cost estimates that were prepared in 2015 by S&L. The purpose of this update was to capture any changes that may have occurred at the PSO facilities between 2015 and 2017 that would affect the demolition costs. The unique characteristics of each site were captured by reviewing aerial photographs and general arrangement drawings for each site:

documents that show the location of major facilities on site and the arrangement inside the power blocks, such as the boiler building, the turbine building, etc. S&L also performed a site visit to the Northeastern Plant to meet with plant representatives to ensure all major modifications made to the plants since the 2015 Demolition Studies were properly reflected in the 2017 update studies. Because S&L performed a similar demolition study in 2015, and because most of PSO's generating units did not have significant new investments or retrofits since that time, it was not necessary to incur the expense associated with detailed visits to each of PSO's plants for the purposes of the 2017 demolition estimates.

Mr. Meehan further testified that this data was reviewed in more detail to finalize the scope of the cost estimates and the assumptions that were used to develop the cost estimates. For example, in many instances, we assumed that there was sufficient room on site to dispose of all the non-hazardous debris, rather than pay for offsite disposal. We also assumed that it would not be necessary to remove the tens of thousands of feet of underground piping and wiring from the sites as well as buried tanks and underground foundations to reduce the overall demolition costs. These assumptions minimize the dismantling cost estimate and result in a very reasonable cost estimate for dismantling the facility. The use of these assumptions was consistent with the 2015 studies.

According to Mr. Meehan demolition cost estimates that S&L prepared for PSO as being in the mid-range between a high-level conceptual estimate and a more detailed budget estimate based upon project specific budgetary bids from contractors. Labor costs and scrap values were based upon current applicable market rates.

Mr. Meehan testified that the demolition studies conducted by S&L been found to be reasonable and prudent by other Public Utility Regulatory Commissions.

The Public Utility Commission of Texas order in PUC Docket No. 40443 that found in its findings of fact that:

> *The plant demolition studies SWEPCO used to develop terminal removal cost salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment.*

In addition, the Indiana Utility Regulatory Commission in Cause No. 44075 found that:

> *The evidence of record shows that S&L is well-qualified with specific expertise in producing demolition cost estimate studies and that the S&L demolition cost estimates are clearly substantiated and based on site specific data, assumptions consistent with prudent industry practices and previous S&L demolition estimates. This Commission has long accepted and relied on site-specific S&L demolition cost studies for purposes of establishing depreciation rates.*

According to Mr. Meehan, the updated 2017 demolition cost estimates capture current labor, material, and scrap pricing adjustments. Changes in labor rates and market value of copper and steel were the primary reasons for the differences in estimated demolition costs. In addition, there were changes in some of the estimates that captured changes that occurred at the facilities after the 2015 demolition cost estimates were prepared.

Table 2 – Comparison of Scrap Prices

	2015 ($/ton)	2017 ($/ton)
Mixed Steel Value	$ 232	$ 166
Copper Value	$ 5,088	$ 3,227
Stainless Value	$ 1,220	$ 1,227

The total estimated increase in labor cost is approximately $19.6 million.

Mr. Meehan testified that the demolition cost estimates consider various scrap metals based on the weight of materials at each plant site. S&L received spot prices from a local recycling facility in Oklahoma for scrap metals including mixed steel, copper and stainless steel. These scrap prices were then applied in the estimates. The localized scrap prices received are inclusive of the full cost to sort and separate scrap materials, transport to a recycling facility and the credit from the recycler.

The decrease in scrap value from the 2015 study has decreased the positive net salvage in the estimates by approximately $18.5 million according to Mr. Meehan.

Mr. Meehan testified that in substantially most cases generating facilities do not have equipment that can be salvaged. An active market does not always exist for used power plant equipment from plants demolished at the end of their useful lives. Quite often, advances in technology produce equipment in the market that is more efficient than equipment that exists in older facilities.

In Mr. Meehan's opinion, these estimates were carefully prepared, using standard and accepted estimating techniques and the best information available and industry experience. The assumptions made in the studies are reasonable.

JOHN J. SPANOS

Mr. John J. Spanos, Senior Vice President of the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), testified on behalf of PSO.

Mr. Spanos testified that the results of the depreciation study, which is based on established and supported methods and procedures, results in the most reasonable depreciation rates for the Company's assets. The overall result of the depreciation study is a net increase in depreciation expense. According to Mr. Spanos, this is in large part the result of service life and net salvage estimates that form the basis of the current depreciation rates, which are currently based on the following unreasonable assumptions:

- That some of the Company's substation equipment (such as transformers and circuit breakers) will be in service for more than 250 years.
- That some of the Company's street lighting assets will be in service for more than 400 years.
- That some of the Company's office buildings and service centers will remain in service for more than 200 years.
- Failure to account for the significant investments in pollution control equipment for Northeastern Unit 3.

Mr. Spanos testified that the Company's currently approved depreciation rates and in particular the service lives, are for many accounts, well outside a range of industry norms and as a result will not properly or equitably recover the cost of the Company's assets over their service lives. For this reason, an increase in depreciation expense is necessary to bring the Company's depreciation rates more in line with reasonable and appropriate life and net salvage expectations for the Company's assets. According to Mr. Spanos, his depreciation study achieves this objective, and produces the most appropriate depreciation rates for the Company's assets.

Table 1 below sets forth a comparison of the current depreciation rates and resultant expense to the proposed depreciation rates and expense by function as of December 31, 2016.

Table 1

	Current		Proposed	
Function	Rates	Proforma Expense	Rates	Expense
Steam	2.14	$ 28,767,126	3.69	$ 49,674,822
Other	2.43	$ 3,810,749	3.87	$ 6,080,057
Transmission	2.16	$ 17,915,352	2.53	$ 20,950,776
Distribution	2.75	$ 63,672,248	3.29	$ 76,238,432
General	2.12	$ 3,083,569	3.53	$ 5,143,499
Unrecovered Reserve Amortization	-	$ 0	-	$ 313,063
Total		$117,249,044		$158,400,649

According to Mr. Spanos, one of the primary reasons for the change in depreciation rates is that the current depreciation rates are inadequate to recover the Company's investments over the service lives of its assets. Specific major components that caused rates to change by function are as follows:

- Steam Production Plant: The primary drivers of the increase in depreciation for this function of $20.9 million are additional plant investment in Northeastern Unit 3, as well as more negative net salvage estimates for the Company's steam production plants. This change in net salvage incorporates updated decommissioning studies, as well as the need to escalate these costs to the date at which the plants will be decommissioned in order to recover the full costs of each plant.
- Other Production Plant: The primary driver of the increase of $2.3 million for other production plant is more negative net salvage estimates, which are due to the same factors as discussed above for steam production plant.
- Transmission Plant: The primary drivers of the increase of $3.0 million for transmission plant are changes to the service life and net salvage estimates for some accounts.
- Distribution Plant: The primary driver of the increase in depreciation expense of $12.6 million for distribution plant is the result of the recommendation to use more reasonable service life estimates for the Company's distribution assets.
- General Plant: The primary reasons for the increase of $2.1 million is a more reasonable estimate for the Company's general plant structures, as well as updating the depreciation rates for amortization accounts to reflect the recommended amortizations.

Mr. Spanos further testified that depreciation is a process of determining the timing of the recovery of the Company's capital investments. Reductions in depreciation expense, such as adopted by the Commission in the previous cause, do not actually reduce customer rates over the long run. Instead, reducing depreciation rates defers these costs to the future - resulting in higher depreciation expense in future depreciation studies, all else being equal. Because the recovery of the Company's costs have been deferred in previous rate cases, the increase in depreciation expense in the instant case is higher than it otherwise would be. Further, because accumulated depreciation reduces rate base, if depreciation rates are too low, then rate base will be higher than it otherwise would be. Customers must then pay a return on this higher rate base, and because the rate of return is typically higher than depreciation rates, the impact of a higher rate base will tend to exceed any reduction in depreciation rates over time. For this reason, setting depreciation rates too low will typically result in a higher overall cost to customers in the long run.

RESPONSIVE TESTIMONY

Oklahoma Industrial Energy Consumers, Wal-Mart Stores, LP, and Sam's East, Inc.

DAVID C. PARCELL

My name is David C. Parcell. I am a Principal and Senior Economist of Technical Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Road, Richmond, Virginia 23229.

I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since

1970. I have previously filed cost of capital testimony in over 550 public utility ratemaking proceedings before some 50 regulatory agencies in the United States and Canada. Much of this testimony has been on behalf of commission staffs. Attachment 1 provides a more complete description of my education and relevant work experience.

I have been retained by the Oklahoma Industrial Energy Consumers ("OIEC") and Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart") to evaluate the cost of capital ("COC") aspects of the current filing of Public Service Company of Oklahoma ("PSO"). I have performed independent studies and am making recommendations of the current COC for PSO. In addition, since PSO is a subsidiary of American Electric Power Company, Inc. ("AEP" or "Parent"), I have also evaluated AEP in my analyses.

My overall COC recommendations for PSO are shown on Schedule 1 of Exhibit DCP-1 and can be summarized as follows:

	Percent	Cost	Return
Long-Term Debt	51.49%	4.60%	2.37%
Common Equity	48.51%	9.00%	4.37%
Total	100.00%		6.73%

This proceeding is concerned with PSO's regulated electric utility operations in Oklahoma. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. I have used the actual capital structure of PSO, as proposed in the Company's filing, in my analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the cost rate for long-term debt (4.60 percent) of PSO, again as proposed in the Company's filing.

The third step in the cost of capital calculation is the estimation of the cost of common equity ("ROE"). I have employed three recognized methodologies to estimate the ROE for PSO. Each of these methodologies is applied to a group of proxy utilities similar to PSO/AEP and the group of electric utilities used by PSO witness Michael J. Vilbert. These three methodologies and my findings are:

Methodology	
Discounted Cash Flow (DCF)	8.5%
Capital Asset Pricing Model (CAPM)	6.4%
Comparable Earnings (CE)	9.5%

My recommendation for PSO focuses on the results of the DCF (8.5 percent) and CE (9.5 percent) analyses. I recommend the mid-point of this range, or 9.0 percent, for PSO.

My DCF analyses employ the following:

Stock prices – average price for each proxy company for the three-month period June-August 2017 (P)

Dividend – current annualized dividend rate for each proxy company (D)

Dividend yield – D/P times (1 + .5 g)

Growth rate – (g) derived from use of five indicators of expected growth for each proxy company

Five-year historic retention growth;
Five-year historic growth rates in dividends per share, earnings per share and book value per share;
Five-year prospective growth rate in retention growth;
Five-year prospective growth rates in dividends per share, earnings per share, and book value per share; and,
Five-year projections in earnings per share growth by security analysts.

Use of this information produced a broad range of DCF cost rates of 7.0 percent to 8.5 percent, with the highest growth rates producing DCF cost rates of 8.3 percent to 8.5 percent. My DCF recommendation focuses on the highest of the indicated growth rates and resulting DCF cost rates, or 8.5 percent.

My CAPM analyses employ the following information:

Risk-free rate – average yield of 20-Year US Treasury bonds for the period June-August 2017 (2.58 percent);

Beta – Value Line beta for each proxy company; and,

Risk premium – differential between stock returns of S&P 500 and 20-Year US Treasury bonds (5.8 percent).

Use of this information produced CAPM cost rates of 6.1 percent to 6.7 percent (6.4 percent mid-point). Given the relatively low CAPM results, as well as the fact that US Treasury bond yields have been negatively impacted by Federal Reserve policies, I gave little weight to the CAPM results in making my ROE recommendations.

My CE analyses examined historic (i.e., 2002-2016) and prospective (i.e., 2017-2022) returns on equity or the proxy companies, as well as the market-to-book ratios ("M/B") of these companies. I found that recent and prospective ROEs of 10 percent to 11 percent have been accompanied by M/Bs of 150 percent and over, indicating that these levels of ROEs exceed the required returns for utilities. My CE recommendation is a range of 9 percent to 10 percent, with a mid-point estimate of 9.5 percent.

My testimony also discusses the cost of equity recommendation of PSO witness Michael J. Vilbert, in which a ROE of 10.0 percent is recommended. I demonstrate that each of Dr. Vilbert's ROE methodologies over-states the ROE for PSO.

Dr. Vilbert's DCF analyses begin on the "right track" with results of 8.8 percent (Simple DCF) and 7.8 percent (Multi-stage DCF). However, he errs in "adjusting" these results first to overall costs of capital, using market values of equity rather than the required book values as used in utility ratemaking, and then "readjusting" these overall costs of capital to PSO's book value cost of capital. Such a series of "adjustments are not appropriate and produce results that defy logic, as the 7.8 percent to 8.8 percent DCF results for his proxy companies is much below his adjusted DCF recommendation for PSO (i.e., 9.2 percent to 10.5 percent), notwithstanding the demonstrated fact that PSO is no more risky than the proxy companies. I also indicate that this adjustment process is unorthodox and apparently has not been previously relied upon by regulatory commissions.

I also demonstrate that Dr. Vilbert's CAPM (which he refers to as Risk Positioning) methodologies over-state the ROE for PSO. Dr. Vilbert uses projected yields on US Treasury bonds as the risk-free rate which is speculative and is in contrast with the proper use of the actual yields of US Treasury bonds as the risk-free rate. In addition, Dr. Vilbert's risk premium inputs (i.e., 6.9 percent to 7.9 percent) overstates the proper risk premium, as it relied only on the income component of US Treasury bonds and compares this to the total return (income component as well as capital gain component) of common stocks.

Finally, I demonstrate that Dr. Vilbert's claim that PSO has "specific risks", that require an incremental return over that of the proxy companies, is improper. Any "specific risks" that PSO is perceived to have is considered by the rating agencies in assigning PSO ratings. Given that PSO has superior ratings to most of the proxy companies, it is apparent that, given all of the Company's risks, it is perceived to have below-average risk, not above-average as Dr. Vilbert's recommendations imply.

DAVID J. GARRETT

The responsive testimony of David J. Garrett was filed September 21, 2017 on behalf of Oklahoma Industrial Energy Consumers ("OIEC") and Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively, "Wal-Mart"). Mr. Garrett is testifying in response to the direct testimonies of three witnesses of Public Service Company of Oklahoma ("PSO" or the Company). Part I of his responsive testimony addresses the direct testimony of Pauline M. Ahern regarding general ratemaking theory and fair rate of return principles. Part II of his responsive testimony addresses the direct testimony of John J. Spanos regarding PSO's proposed depreciation rates, and it also addresses the direct testimony of Thomas J. Meehan regarding PSO's proposed decommissioning costs, which directly affects the Company's production net salvage and depreciation rates.

Part I – Risk and Return

The legal standards governing the issue of fair rate of return indicate that the allowed return should be based on the cost of capital. When the awarded ROE is set far above true cost of equity, it runs the risk of violating the Supreme Court's standards directing that the awarded return should be based on the cost of capital. In addition, an excessive ROE award would result in harmful impacts to the state's economy because it would permit an excess wealth transfer from Oklahoma ratepayers to PSO's out-of-state shareholders and the Internal Revenue Service.

This outflow of funds from Oklahoma's economy would not benefit its businesses or citizens. Instead, Oklahoma businesses, such as OIEC member companies and Wal-Mart, would be less competitive with businesses in surrounding states, and individual ratepayers will receive inflated costs for basic goods and services, along with higher utility bills.

Risk is among the most important factors for the Commission to consider when determining the allowed return. In order to comply with this standard, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees. In her direct testimony, Ms. Ahern states that utilities face a variety of "business risks" including the allowed return on common equity, depreciation expense, customer mix, and other firm-specific risks. While it might be accurate to describe these factors as "risks," Ms. Ahern's testimony on this issue is misleading because rational investors do not expect a return for assuming such firm-specific business risks. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk.

Increasing a company's debt ratio from zero to some positive amount will have an increasing effect on both its cost of equity and cost of debt, however, the primary cost the Commission should be concerned with is the overall weighted average cost of capital, which should be the primary driver of the awarded rate of return in this case. It is misleading to simply suggest that increasing PSO's debt ratio will increase its cost of equity, when in reality, raising PSO's debt level would actually decrease its weighted average cost of capital ("WACC"). As with all of its costs, PSO has a duty to operate at the lowest reasonable weighted average cost of capital. This means that not only should PSO's cost of equity and awarded ROE reflect the Company's very low risk, but also PSO's debt ratio should be high enough to minimize is weighted average cost of capital. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. utilities can increase their revenue requirement by increasing their WACC, not by minimizing it. Because there is no incentive for a regulated utility to minimize its WACC, a regulator standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios.

Ms. Ahern claims that since the return on common equity set in this proceeding will be applied to the book value of PSO's rate base, it is reasonable to look at the projected returns on book equity of non-regulated firms. Ms. Ahern's premise makes no sense and is illogical. Cost of capital witnesses routinely conduct their analyses on a group of "proxy" companies that include regulated utilities. This practice likely stems from "corresponding risk" standard set forth by the Hope Court. The risk inherent in the equity of competitive firms is simply not comparable to the risk inherent in the equity of regulated utilities. This is because the regulated utility industry is essentially the least risky industry in the entire country.

Part II – Depreciation

In this case, PSO is proposing a substantial increase to depreciation expense of about $40 million. As demonstrated by the evidence presented in this testimony, it would not be reasonable to accept PSO's filed position regarding depreciation expense. PSO's proposed increase to depreciation expense is unreasonable due to several factors, which are summarized as follows:

1. In contradiction to the Commission's recent order in PSO's prior rate case, PSO is proposing to add contingency and escalation factors to the Company's terminal decommissioning costs, which unreasonably increases the proposed depreciation expense for PSO's production accounts.

2. For several transmission, distribution, and general accounts, PSO is proposing service lives that are shorter than those indicated by the Company's historical retirement data, which results in unreasonably high proposed depreciation rates for these accounts.

3. PSO chose to exclude a substantial account from its depreciation study – Account 303 – which includes a balance of more than $50 million for the Company's software systems. PSO is proposing an amortization period of only five years, and has offered virtually no support or justification for this position. PSO's own witness has recommended amortization periods of up to 15 years for this account.

For these reasons, it would not be reasonable to accept the Company's proposed increase to depreciation expense. OIEC is proposing two options for adjustments to PSO's proposed increase to depreciation expense, which are summarized as follows: (1) Option One involves accepting portions of PSO's proposed rate increases for its production accounts, as explained further below, while removing the escalation and contingency factors from its proposed decommissioning costs, pursuant to the Commission's recent order in PSO's prior rate case. In addition, the depreciation rates that were recently ordered for PSO's transmission, distribution, and general accounts would stay the same. Finally, Option One would also include OIEC's proposed adjustment to Account 303, since that issue was not addressed in PSO's prior rate case. Accepting Option One would result in an increase to PSO's current depreciation expense of about $9 million. (2) Option Two involves changing PSO's currently-approved depreciation rates based on the Company's proposal offered in this case with reasonable adjustments. Accepting Option Two would result in a substantial increase of about $22 million to PSO's current depreciation expense. Option One is the preferable choice in this case. Although accepting Option One would result in a substantial increase in depreciation expense for PSO, it would also provide more relief to rate payers than Option Two, in light of the significant base rate increase proposed by PSO in this case. The impact to depreciation expense resulting from both options is illustrated below in the following tables.

Figure 1:
Option One: Accept Rate Increases to Production Plant

Plant Function	Plant Balance 6/30/2017	PSO Proposal	OIEC Proposal	OIEC Adjustment
Intangible	$ 51,158,691	$ 10,002,988	$ 5,009,816	$ (4,993,173)
Production	1,562,178,971	59,052,499	53,223,445	(5,829,054)
Transmission	845,997,944	21,245,650	18,166,631	(3,079,019)
Distribution	2,389,887,504	78,220,567	65,282,209	(12,938,358)
General	169,512,415	5,952,814	3,730,822	(2,221,992)
Northeastern 4				(4,141,553)
Total	$ 5,018,735,525	$ 174,076,209	$ 145,014,613	**$ (33,203,149)**

Accepting Option One would increase PSO's current depreciation expense by about $9 million, and would be more reflective of the rates recently approved by the Commission.

Figure 2:
Option Two: Consider Rate Changes for All Accounts

Plant Function	Plant Balance 6/30/2017	PSO Proposal	OIEC Proposal	OIEC Adjustment
Intangible	$ 51,158,691	$ 10,002,988	$ 5,009,816	$ (4,993,173)
Production	1,562,178,971	59,052,499	53,223,445	(5,829,054)
Transmission	845,997,944	21,245,650	20,568,389	(677,261)
Distribution	2,389,887,504	78,220,567	74,351,620	(3,868,947)
General	169,512,415	5,952,814	5,560,389	(392,425)
Northeastern 4				(4,141,553)
Total	$ 5,018,735,525	$ 174,076,209	$ 158,315,350	**$ (19,902,412)**

Accepting Option Two would result in a substantial increase of about $22 million to PSO's depreciation expense.

It is important not to overestimate depreciation rates. The issue of depreciation is essentially one of timing. Under the rate base rate of return model, the utility is allowed to recover the original cost of its prudent investments required to provide service. Depreciation systems are designed to allocate those costs in a systematic and rational manner – specifically, over the service life of the utility's assets. If depreciation rates are overestimated (i.e., service lives are underestimated), it encourages economic inefficiency. Unlike competitive firms, regulated utility companies are not always incentivized by natural market forces to make the most economically efficient decisions. If a utility is allowed to recover the cost of an asset before the end of its useful life, this could incentivize the utility to unnecessarily replace the asset in order to increase rate base, which results in economic waste. Thus, from a public policy perspective, it is preferable for regulators to ensure that assets are not depreciated before the end of their true useful lives. While underestimating the useful lives of depreciable assets could financially harm current ratepayers and encourage economic waste, unintentionally overestimating depreciable lives (i.e., underestimating depreciation rates) does not harm the Company. This is because if an asset's life is overestimated, there are a variety of measures that regulators can use to ensure the utility is not financially harmed. One such measure would be the use of a regulatory asset account. In that case, the Company's original cost investment in these assets would remain in the Company's rate base until they are recovered. Moreover, since the Company's awarded and earned returns on equity are far above its true cost of equity, the Company's shareholders further benefit from the excess wealth transfer from ratepayers while these costs are in rate base. Thus, the process of depreciation strives for a perfect match between actual and estimated useful life. When these estimates are not exact, however, it is better that useful lives are overestimated rather than underestimated.

Decommissioning Costs

When a production plant reaches the end of its useful life, a utility may decide to decommission the plant. In that case, the utility may sell some of the remaining assets. The proceeds from this transaction are called "gross salvage." The corresponding expense associated with decommissioning the plant is called "cost of removal." The term "net salvage" equates to gross salvage less the cost of removal. When net salvage refers to production plants, it is often called "terminal net salvage," because the transaction will occur at the end of the plant's life. Typically, when a utility is requesting the recovery of a substantial amount of terminal net salvage costs, it supports those costs with site-specific decommissioning studies. Terminal net salvage costs are unlike other costs requested in a rate case. Specifically, while other proposed costs might be based on a recent test year involving actual expenses incurred by the utility, decommissioning costs are often estimated to occur many years or decades in the future. Moreover, the utility may never even incur the decommissioning costs they are proposing. Thus, decommissioning costs are not as "known and measurable" as other costs proposed in a rate case. Furthermore, decommissioning studies are often overestimated, as they usually do not contemplate less expensive alternatives to complete demolition and often include substantial contingency factors that arbitrarily increase the cost estimate, as is the case here. Nonetheless, decommissioning studies provide some measurable basis upon which to estimate the utility's terminal net salvage, and should be viewed as a minimum prerequisite for any recovery of such costs. In this case, PSO's decommissioning studies were conducted by Sargent & Lundy and sponsored in the direct testimony of Mr. Meehan.

Contingency Factor

PSO's decommissioning studies include direct and indirect cost estimates to dismantle PSO's generating facilities, which include labor, material, and scrap value estimates. However, in addition to these cost estimates, Mr. Meehan applied a 15% contingency on the labor, 15% contingency on material, a negative 15% contingency on scrap value and a 15% contingency on the indirect portions of the estimates. These contingency factors were applied to the cost estimates for each one of PSO's generating facilities, and add an additional 15% of costs on top of the base dismantlement cost estimates (and reduce positive scrap value by 15%). The total amount of the contingency factors is greater than $22 million. In PSO's prior rate case the Commission did not approve PSO's proposed contingency factors. In a ratemaking context, ratepayers should be not be charged for costs that are entirely "unknown" by definition.

Furthermore, these contingency factors fail to account for the possibility that PSO's proposed decommissioning costs might be overestimated (and scrap value underestimated). For these reasons, it is not appropriate to include been calculated without inclusion of the contingency factors.[2]

Escalation Factor

To calculate his proposed net salvage rates for PSO's production accounts, Mr. Spanos escalated the decommissioning cost estimates provided by Mr. Meehan by 2.5% each year until the estimated retirement year for each generating facility. This escalation factor would add more than $100 million to PSO's proposed decommissioning costs.3 There are two important reasons the Commission should disallow the cost escalation factor applied by Mr. Spanos. First, it is not appropriate to escalate a cost that is likely overstated, is not known and measurable, and moreover, may never even occur as estimated by the Company. The discussion presented above should lead us to question whether to charge current ratepayers for future decommissioning costs at all, much less whether those costs should be escalated. The second problem with the Company's cost escalation factor is a technical one: It is not proper to charge current ratepayers for a future cost that has not been discounted to present value. In PSO's previous rate case, the Commission adopted OIEC's proposed depreciation rates for the Company's production accounts, which did not include the escalation factor.

Mass Property Analysis

In order to estimate the service lives of PSO's mass property accounts the Company's property data was organized to create an observed life table ("OLT") for each account. The data points on the OLT can be plotted to form a curve (the "OLT curve"). The OLT curve is not a theoretical curve, rather, it is actual observed data from the Company's records that indicate the rate of retirement for each property group. The curve-fitting process involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. While the Company and I used similar curve-fitting approaches in this case, the curves I selected for these accounts provide a better mathematical fit to the observed data, and provide a more reasonable and accurate representation of the mortality characteristics for each account. Form many of the mass property accounts, the Company selected a curve that underestimates the average remaining life of the assets in the account, which results in unreasonably high depreciation rates and expense.

Account 303 – Software

Account 303 includes the Company's software systems. At December 31, 2016, there was a balance of $51.2 million in this account. Even though this account is the largest of the Company's amortized accounts, PSO chose not to include it in the depreciation study or provide any testimony in support of the five-year proposed amortization period. A five-year amortization period for this account results in an amortization expense of more than $10 million. By choosing a five-year amortization period for Account 303, the Company is suggesting that its software

[2] *See* Exhibit DJG-2-4 thru Exhibit DJG-2-7.

[3] *See* Exhibit JSS-2 (depreciation study) p. VIII-6.

programs will last only five years, on average, which results in an excessive proposed expense level. While a five-year service life estimate might be appropriate for basic consumer software systems, it is insufficient to accurately describe the service life of major software systems. Unlike basic consumer software systems, large enterprise software systems can be customized to the specific needs of the company. These modular systems require substantial upfront engineering costs along with periodic maintenance and support fees to ensure that the system performs reliably over a long period of time. For example, many utility companies rely on Enterprise Resource Planning ("ERP") systems comprising a suite of modular applications that collect and integrate data from different facets of the firm. ERP systems are designed to provide long term solutions to companies. SAP is one of several providers of ERP systems. According to a report by CGI Consulting Services, SAP systems can last 25 – 30 years. Given the extremely high installation costs for these complex systems as well as the annual maintenance fees, it is not surprising that companies using ERP systems would demand that the systems last longer than 10 years.

Although it would not be unreasonable to consider a 15 or 20-year amortization period for the assets in Account 303, I am recommending a more conservative 10-year amortization period for this account in the interest of reasonableness. I have calculated the amortization expense adjustment for this Account under a 10-year amortization period, which results in an adjustment in amortization expense of $4.9 million.

MARK E GARRETT

<u>Witness Identification, Purpose of Testimony and Importance of the Case</u>

Mr. Garrett's testimony addresses various revenue requirement issues and presents OIEC's recommended revenue requirement in this case. A summary of the OIEC impacts is shown below:

Rate Increase Proposed by PSO	$ 169,667,526
OIEC Adjustments	$ (117,336,487)
Riders rolled into Base Rates	$ (24,000,000)
Rate Increase after OIEC Adjustments	**$ 28,331,039)**

In its Application, PSO seeks a $169 million rate increase, which represents a 28.33% increase in base rates. This is one of the largest rate increases ever sought in the state of Oklahoma. In December of last year, the Commission established new rates for PSO. This case was filed on the heels of the Company's last rate case, Cause PUD 201500208. In fact, this case was pancaked on top of the last case, half way through the first year of the new rates from that case.

It appears that the Company is trying to relitigate many of the issues it lost in the last rate case. These issues include depreciation expense, payroll costs, incentive compensation and other O&M expense levels. The Commission set the appropriate level for these costs, and implemented them in January of this year. Yet, the utility is seeking to change these cost levels a short 6 months later. This is inappropriate. In reality, the purpose of this case was supposed to be to (i) recover capital investments associated with the remaining costs of PSO's Environmental Compliance Plan ("ECP") for assets that were not completed and in service in the Company's last rate case and (ii) recover capital investments associated with the Company's implementation of automated meters (AMI). It was not meant to be an opportunity for the Company to relitigate losses in the last case.

Rate Base – 6Month Post-Test Year Adjustments

Mr. Garrett propose adjustments to update the Company's rate base accounts to their balances at June 30, 2017. In Oklahoma, the Commission is required by law (Title 17 § 284) to give effect to known and measurable changes that occur within six months of test year end. In this application, the 6 month cut-off period for post test year adjustments is June 30, 2017. In virtually every litigated rate case since Cause No. PUD 200400610, ONG's 2005 rate case, which was the first rate case heard by the Commission after passage of the 6-month rule in Title 17 § 284, the Commission has used this approach. OIEC's adjustments to the Company's pro forma rate base are set forth in Mr. Garrett's responsive testimony.

Prepaid Pension Asset

Mr. Garrett proposes to reduce PSO's prepaid pension balance by $36,508,316, which represents the unexplained, and unsupported, starting balance from 2003 in the Company's prepaid pension calculations. The Company cannot account for what they claim is an existing starting balance. Without any support for this balance, it cannot be included in rates. The Company indicated that the supporting information was unavailable. In the Company's 2003 rate case, the utility used a test year of June 30, 2003 with a 6-month post-test year update period that ran through December 31, 2003. No prepaid pension asset was presented in that case. If there had been a prepaid pension asset in 2003, the time to include it in rate base would have been in that rate case. The revenue requirement impacts of this adjustment is $(3,766,782).

Disallowed Incentives in Rate Base

Each year, PSO capitalizes a portion of its incentive plan payments. These capitalized incentives are included in rate base where they earn a return. The Commission has consistently excluded 50% of PSO's short-term and 100% of the Company's long-term incentives from operating expense. In order to consistently apply the Commission's treatment of incentive compensation, the same portion of PSO's incentive payments excluded from operating expense for ratemaking purposes must also be excluded from rate base. If not, the Company will earn a return on, and eventually recover from ratepayers, compensation associated with incentive plans the Commission has disallowed. At test year end, $37,645,259 was included in rate base for incentives costs that should be removed. This adjustment is necessary to make the Commission's treatment of incentive costs in rate base consistent with its treatment of PSO's incentive costs in operating expense in PSO's prior litigated cases, including PUD 200600285 and PUD 200800144 and PUD 201500208. The revenue requirement impact of this adjustment is $(3,884,087)

Annual Incentive Compensation Expense

PSO seeks to include $9.098 million in rates for annual, short-term incentive expense, based upon the Company's targeted payout for incentive expense, according to the Company. Mr. Garrett proposes to exclude annual incentive expense related to financial performance measures. As a result, Mr. Garrett proposes to reduce the Company's requested level of annual incentive compensation by 75%, or $6,824,159.

PSO's 2016 Annual Compensation Plan is heavily dependent on financial performance measures. As in prior years, PSO's incentive plans are based upon various financial and operational measures, however, the overall funding available to pay annual incentive compensation is based 75% on AEP's earnings per share (EPS), as it was in PSO's last rate case, PUD 201500208. Under the Company's funding mechanism, regardless of how well individual employees may perform in nonfinancial performance areas such as customer satisfaction and safety, if the Company's EPS is low, payments to employees will be reduced accordingly, even to 0% if needed. Thus, under the Company's incentive compensation plan, corporate earnings is the primary driver in determining whether, and to what extent, incentive compensation will be paid each year. In fact, the Company's 2016 Overview states, "Linking annual incentive compensation to AEP's earnings aligns it with the value created for AEP's shareholders and ensures that AEP meets its shareholder commitments before setting aside dollars for employee rewards."

The 2016 Plan also makes the following statements regarding the 75% Funding Mechanism:

- Further <u>aligns the financial interests of all AEP employees with those of AEP's shareholders</u>;

- <u>Ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before employees are rewarded with annual incentive compensation</u>;

In prior cases, the Commission has consistently reduced the requested levels of incentive compensation based upon the fact that the plans are tied to the Company's financial performance. In PSO's last three litigated rate cases, the Commission reduced PSO's requested annual incentive compensation by 50% based upon the testimony and evidence in those proceedings that the plans were tied to financial performance.

Similarly, in OG&E's last two litigated rate cases, the Commission reduced OG&E's annual incentive plan costs for amounts tied to financial performance. In OG&E's last rate case, PUD 201500151, the requested amounts were reduced by 50% and in OG&E's 2005 rate case, PUD 200500151, the requested amounts were reduced by 60%.

As a general rule, regulatory commissions exclude incentive compensation associated with financial performance. When the costs associated with these plans are excluded, the rationale is generally based on one or more of the following reasons:

1) Payment is uncertain;
2) Many of the factors that impact earnings are outside the control of most company employees;
3) Earnings-based incentive plans can discourage conservation;
4) The utility assumes no risk associated with incentive payments;
5) Financial incentives should be paid out of increased earnings;
6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion.

Even though regulators routinely exclude financial-based incentive compensation payments based on one or more of the reasons outlined above, this does not mean that companies cannot offer financial-based incentives. However, when a financial-based incentive package is properly constructed, there will be ample additional earnings to fund these payments. Thus, ratepayers do not need to subsidize incentive plans designed to increase earnings.

Garrett Group LLC conducted an Incentive Compensation Survey of the 24 Western States in 2007, and updated it in 2015. The survey shows that the vast majority of the states surveyed follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. None of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule.

The argument that incentives should be included in rates because the amount is reasonable when compared with the amounts paid by other utilities misses the point. The question for regulators is not whether the amount paid for incentives is reasonable, but whether the incentives themselves are necessary for the provision of service. Further, when it comes to financial-based incentives, regulators ask who benefits more from these payments, ratepayers or shareholders.

Although utilities are free to offer whatever compensation package they want to offer, most commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings. Also, as stated above, because incentive pay related to financial performance is generally disallowed, most of the utilities that PSO competes with for talent generally do not recover all of their incentive compensation in rates. Therefore, PSO is not put at a competitive disadvantage when its incentive pay is similarly adjusted.

Long-term Stock Incentive Compensation Plan

The Company is proposing to recover $3,106,766 for its long-term incentive plan, which is the amount in pro forma operating expense after PSO's adjustment to increase test year expense to targeted levels for long-term incentives.

The long-term plan provides grants and awards in the form of performance units and restricted stock units (RSUs), both of which are generally similar in value to shares of AEP common stock. The performance units are granted based on two equally weighted performance measures: three-year total shareholder returns, and three-year cumulative EPS relative to a Board-approved target. As such, the Long-Term Incentive Plan is designed to align the interest of AEP's management with the interest of shareholders and to promote the financial success and growth of AEP.

Mr. Garrett testified that stock incentive compensation payments to officers, executives and key employees of a utility are generally excluded for ratemaking purposes. Officers of any corporation have a legal, fiduciary duty to put the interests of the corporation first. This means that these individuals are required to put the interests of the company above the interest of the customers. Since the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interest of the shareholders first.

The results of the Garrett Group Incentive Survey, discussed in the previous section of this testimony, show that most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that long-term, stock-based incentives are not allowed in virtually every state. In the synopsis of the incentive survey results from each state that was included in the prior section of this testimony, the treatment of long-term stock based incentives in each state is underlined. According to the survey, 20 of the 24 western states exclude all or virtually all long-term stock-based incentive pay. In the other four states, the issue has not come up. Mr. Garrett's proposed adjustment removes 100% of the cost of the plan in pro forma operating expense in the amount of $(3,106,766).

Supplemental Employee Retirement Plan ("SERP")

Mr. Garrett testified that the Company provides supplemental retirement benefits to officers, and division presidents of the Company. Supplemental retirement plans for highly compensated individuals are provided because benefits under the general pension plans are subject to certain limitations under the Internal Revenue Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $265,000 for 2015 and $270,000 for 2016. Retirement benefits on compensation levels in excess of annual compensation limits are paid through supplemental plans. Supplemental retirement plans for highly compensated employees are designed to provide benefits in addition to the benefits provided under the general pension plans of the company. The amount of SERP costs included in PSO's filed cost-of-service was $349,862, which is comprised of $96,780 for PSO and $253,082 for AEPSC. Mr. Garrett recommends excluding the SERP costs in this case as it has consistently done in the past.

Rate Case Expense

Mr. Garrett testified that PSO's requested rate case costs are significantly overstated. For example, an increase from $200,000 to $500,000 for outside legal fees appears excessive. In addition, $150,000 for a Return on Equity ("ROE") witness is far above market, which is between $25,000 and $50,000. Further, PSO's additional, and cumulative, ROE witness at $100,000 should be paid by shareholders. Also noteworthy, the Company seeks to include $107,000 for a demolition study that has been presented now in the Company's last three rate cases in Oklahoma. Finally, the Company seeks $43,500 for notice costs when those costs have been $5,000 in the past two rate cases. In Mr. Garrett's opinion, rate case expense costs should be scrutinized much more closely than they have been in the past. Moreover, the Commission should understand that not all rate case costs should be borne by ratepayers. Only the necessary costs to process a rate case should be borne by ratepayers and these necessary costs should be evaluated using a least-cost standard. Ratepayers should not be burdened with unreasonably inflated legal costs and expert witness fees, especially when the testimony appears to be self-serving shareholder testimony.

Mr. Garrett recommends that rate case expense be reduced from $1,161,066 to $590,566, and that rate case costs be recovered over a 4-year rather than a 2-year period. The longer recovery period will help lower rates now. A 4-year amortization of these costs results in an adjustment of $(432,892).

Storm Damage Expense

Since the Company is insulated from under-recovery through the tracker mechanism, there is no need to increase base rates now based on anticipated increases in storm damage expense in the future. In my opinion, the Commission should leave test year expense level where it is, and should continue to allow PSO to recover its excess storm expense through the approved tracker mechanism. This recommendation results in an adjustment of $(8,263,753)

Payroll Expense

Mr. Garrett testified that PSO annualized its test year costs and then added a 3.5% wage increase on top of that. Mr. Garrett testified that an annualization that multiplies a final pay period by 12 or 26 is only appropriate if the final pay period is representative of ongoing levels. Further, an additional increase for pay raises based on the nominal amount of the pay raises is not appropriate because payroll levels do not increase by the nominal amount of a pay raise. In other words, a 3.5% pay raise will almost never result in a 3.5% increase in payroll expense levels. Other factors can greatly impact payroll expense. These factors include: (1) the normal turnover; (2) workforce reorganizations; (3) productivity gains; and (4) capitalization ratio changes. All of these factors can impact overall payroll cost levels as much or more than pay raises do. For example, in PSO's last rate case, PSO requested a 3.85% increase in payroll costs from $53.096 million in the test year to $55.134 million, based again on post-test year pay raises. However, after that case, payroll costs actually went down by 1.01%, not up by 3.85% as the Company predicted.

PSO's new rates from the Company's last rate case went into effect in January 2017. This means that the reasonable level of payroll costs ordered by the Commission went into effect just eight months ago. Not even one year has passed since the Commission established this level. It is too early to set a new level for payroll costs. The Company's payroll adjustment methodology is unreliable, and not enough time has passes to tell whether or not the level established by the Commission in January of this year is sufficient.

Since the appropriate level for any operating expense is the test year level unless it can be shown that the test year level is not representative of the level that will be in effect during the rate-effective period, the amount that should be included in rates in this case is the test year level.

Thus, Mr. Garrett's adjustments reverse the adjustments recommended by the Company for both PSO and AEPSC allocated costs, in the amounts of $(2,726,115) and $(2,773,667) respectfully.

Production Operating and Maintenance Expense

Mr. Garrett testified that PSO's proposed production O&M adjustments are unreasonable and would result in the Company collecting an excessive level of O&M expenses through its base rates. PSO's proposed adjustment of $293,664 to adjust test year expense for the retirement of Northeastern Unit 4 greatly understates the reduction in expenses that should reasonably result from retirement of the unit. It simply makes no sense that the cost to operate, maintain and staff one coal unit would only be 10% lower than the cost for two coal units, as PSO's adjustment suggests. Mr. Garrett recommends that PSO's test year O&M be reduced by $5.68 million for the Northeastern 4 retirement. This results in an allowed O&M level for Northeastern Unit 3 that is 68% of the level incurred for both Unit 3 and Unit 4, before Unit 4 was retired.

Also, PSO's proposed normalization adjustment (for the other power plants) is flawed in that it assumes that the three-year period used to determine "normal O&M levels" were in fact normal periods. The Company has not presented evidence to support this assumption. Moreover, during this period there were several major abnormal events that could have significantly impacted PSO maintenance expenses. For this reason, PSO's proposed $2.11 million increase to test year production O&M expense should be rejected.

Mr. Garrett adjustments reverse PSO's proposed production O&M adjustment in the amount of $(2,110,317), and reduce the test year O&M for Northeastern Unit 4 Production costs in the amount of $(5,680,000), for a total adjustment of $(7,790,317).

Southwest Power Pool (SPP) Transmission Expenses

PSO recovers SPP transmission expenses through base rates except for third party SPP Schedule 11 charges, which are recovered through the Company's SPPTC Tariff (excluding OK Transco). SPP expenses in base rate have more than doubled in the past four-year period, going from $22.5M in 2012 to $53.419M in the 2016 test year. PSO proposes adjustments primarily to annualize test year SPP charges. The net impact of these proposed adjustments increases SPP test year expense by another $17.64 million, or approximately 33%.

These adjustments are not supported by testimony or workpapers. PSO witness Hamlett indicates that the support for the increase is provided in his testimony and the testimony of PSO witness Ross. However, Mr. Hamlett provides only has one paragraph and a single workpaper page and Ross discusses the general nature of SPP expenses but does not address the specific test year adjustments to SPP expenses proposed by the Company in this case.

The third-party charges underlying the amounts billed from SPP that PSO seeks to recover in base rates include post-test year projected costs. PSO's proposed adjustments fail to meet the "reasonable and necessary" and "known and measurable" standards in Oklahoma, under (Title 17 O.S. § 284).

The SPP charges also include charges from the Company's affiliate, Oklahoma Transco. These affiliate charges include an 11.2% return on equity (ROE), which is significantly higher than the authorized return in Oklahoma. It is inappropriate for PSO to charge ratepayers through an affiliate a higher ROE than it is allowed to recover itself.

Mr. Garrett recommends that PSO's proposed test year adjustments be rejected. This recommendation results in a $16.06 million reduction to the level of SPP charges which PSO proposes to recover through its new base rates.

PSO's testimony in this case indicates that the Company collected approximately $42.88 million of SPP charges through its SPPTC Tariff during the test year. The SPPTC Tariff defines PSO's obligations to support charges recovered under this rider as follows:

> The company will address the reasonableness of SPP Expenses collected through the SPPTC during the next PSO base rate case and in future base rate cases.

Except for the brief mention of the SPPTC charges in Mr. Hamlett's testimony, no PSO witness addresses the reasonableness of specific charges collected through the SPPTC during the test year or in periods since the test year in the Company's last base rate case.

PSO has failed to adhere to the explicit requirement of the SPPTC Tariff with regards to demonstrating the reasonableness of past expenses collected through the SPPTC. For this reason, Mr. Garrett believes that the Commission could, in its discretion, order PSO to refund the $42.88 million of test year charges collected through the SPPTC.

Recovery of Northeastern Unit 4 Costs

PSO is proposing to retire the 460MW Northeastern Unit 4 coal plant in the middle of its useful life, but wants to include both a "return on" and a "return of" the plant costs in rates. The un-depreciated plant balance for Northeastern Units 4 at June 30, 2017 net of associated ADIT was $50.7 million. The annual rate base "return on" this amount would be $5.2 million and the annual depreciation expense is approximately $4.1 million, making the total annual cost to ratepayers about $9.3 million. PSO's proposal to include these costs in rates is inappropriate. Oklahoma law is very clear on this point: only assets "used and useful" for providing utility service may be included in rate base. Further, a plant's "used and useful" status is determined based upon the value of the property used and useful in public service at the time the inquiry was made, thus, in the test year plus six months. Unit 4 was taken out of service in April 2016. Since Unit 4 is no longer in service and is no longer used and useful, it should be removed from rates.

Mr. Garrett provided several relevant examples from Ohio, New Mexico, Texas and Oklahoma, where plants that were not used and useful were removed from rates. He also provided relevant precedent in Oklahoma from OG&E's 1991 rate case, PUD 91-1055. OG&E had taken its Arbuckle generating plant out of service in response to load lost in the economic downturn that occurred at that time, but tried to include the costs of the retired plant in rate base under a theory that the plant could be returned to service when the economy recovered. The

Commission, however, found that the plant was not used and useful because it was no longer in service, and could not be included in rate base. The Commission did allow OG&E the opportunity to return the plant to rate base if it was ever re-powered and returned to service. With the plant excluded from rate base the utility was not able to include the plant's depreciation expense in rates either. In effect, the Arbuckle plant became Plant Held for Future Use. As such, the return on and the return of the plant were both excluded from rates.

Mr. Garrett testified that Northeastern Unit 4 should be excluded from rates because the plant is no longer used and useful. This would leave open the possible return of the plant to rate base if the plant is eventually returned to service – either converted or repowered – in the future. The impact of this adjustment on the revenue requirement is \$(9.37) million.

Public Utility Division

ELBERT D. THOMAS

Elbert D. Thomas is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In this Cause, Mr. Thomas presented PUD's recommendation for his assigned areas in response to the Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

On September 21, 2017, Mr. Thomas filed Responsive Testimony for areas including Refundable Contributions in Aid of Construction ("CIAC"), Customer Deposits, Interest on Customer Deposits, and Franchise Fees.

Mr. Thomas testified that PUD reviewed the Application, direct testimonies, schedules, workpapers, and sponsored exhibits filed by the Company. In addition, Mr. Thomas reviewed PSO's prior workpapers, testimonies, and sponsored exhibits, along with Final Order No. 657877 for Cause No. PUD 201500208 and Final Order No. 639314 for Cause No. PUD 201300217. Mr. Thomas issued data requests and reviewed all responses provided by PSO. Mr. Thomas also reviewed the data requests and responses issued by interveners, including the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers. Lastly, Mr. Thomas testified that PUD conducted multiple onsite audits at the Company's division office in Tulsa, Oklahoma. During the onsite audits, Mr. Thomas reviewed confidential information and conducted interviews with Company witnesses who manage and perform the functions under review. Thomas testified that PUD recommends the Commission accept the following adjustments:

PUD Adjustments:

Customer Deposits: Adjustment No. B-2 to increase Customer Deposits by \$986,714. This will reduce the rate base by (\$986,714). The main element in this review is based on the 13-month average and a six-month post test year amount.

Refundable CIAC – Adjustment No. B-8 to increase Refundable CIAC by \$69,740. This will reduce the rate base by (\$69,740). The main element in this review is based on the six-month post test year amount.

PSO Proposed Adjustment:

Interest on Customer Deposits: Adjustment to increase Interest on Customer Deposits by $846,779. This will increase cost of service by $846,779. The main element in this review is based on the six-month post test year amount.

Mr. Thomas did not propose any adjustments to the remaining areas, which do not have a significant impact on the rate base. Finally, Mr. Thomas testified that he believes these recommendations are fair, just, reasonable, and in the public interest.

DAVID MELVIN

On June 30, 2017, PSO filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. David Melvin is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Senior Public Utility Regulatory Analyst. Mr. Melvin filed Responsive Testimony on September 21, 2017. The purpose of his testimony was to present PUD's recommendations concerning Cause No. PUD 201700151. Mr. Melvin's testimony focused on the following areas of the Application: Plant Operations & Maintenance ("O&M"), American Electric Power Service Company ("AEPSC") affiliate adjustments to O&M, Ongoing Environmental Expenses, Adjustment to O&M for North Eastern Unit #4 ("NE4") Retirement, Adjustment to Normalize Test Year Generation Non-Fuel O&M, Distribution Reliability, Construction Work in Progress ("CWIP"), AFUDC, Red Rock Regulatory Asset, and Plant in Service.

Mr. Melvin testified that PUD reviewed the Application, as well as the testimony and sponsored exhibits of Company witnesses. In addition, Mr. Melvin issued data requests, reviewed data requests and responses, and conducted onsite audits at the Company's division office in Tulsa, Oklahoma. Mr. Melvin testified that after review of Plant O&M, AFUDC, AEPSC affiliate adjustments to O&M, adjustment to O&M for Northeastern Unit #4 Retirement, adjustment to Normalize Test Year Generation Non-Fuel O&M, Capitalized Maintenance, CWIP, Distribution Reliability, Red Rock Regulatory Asset, Ongoing Environmental Expenses, and Plant in Service, he recommended the Commission accept PUD Adjustment H-3 for ($1,791,808) to revise PSO's proposed Adjustment WP H-2-29 (Annual Storm Inc) to a three-year average instead of a seven-year average. Mr. Melvin recommended the Commission accept the following PSO adjustments from Schedule H-3: Adjustment No. WP H-2-18 (Outside Services) reducing Cost of Service ($44,415); Adjustment No. WP H-2-19 (AEPSC) reducing Cost of Service ($5,104,160); Adjustment No. WP H-2-22 (System Reliability) increasing Cost of Service $214,918; Adjustment No. WP H-2-31 (Severe Storm) increasing Cost of Service $5,202,492; Adjustment No. WP H-2-35 (NE4 Adjust) reducing Cost of Service ($293,664); Adjustment No. WP H-2-36 (Gen Normalizing Adj) increasing Cost of Service $2,110,317; Adjustment No. WP H-2-37 (Env. Compl Plan Adj) increasing Cost of Service $300,000; and Adjustment No. WP H-2-38 (InterCo Billing) decreasing Cost of Service ($67,547). Mr. Melvin also recommended the Commission accept PUD Adjustment B-3 for $69,196,225 to increase Plant in Service to include the six months post test year. Mr. Melvin further testified that he recommended the Commission accept PSO's Red Rock Regulatory Asset adjustment presented in WP B-03-3, the balance of $9,050,820 be included in rate base.

Finally, Mr. Melvin testified that PUD believes these recommendations are fair, just, reasonable, and in the public interest.

JASON CHAPLIN

Jason Chaplin is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as an Energy Coordinator. Mr. Chaplin filed Responsive Testimony on September 21, 2017. The purpose of his testimony was to present PUD's recommendations concerning Cause No. PUD 201700151. Mr. Chaplin's testimony focused on the following areas of the Application: Southwest Power Pool ("SPP") Fees and Expenses, Independent Power Producer ("IPP") Credits and Interest, and Amortization of Severe Storm Expense.

On June 30, 2017, Public Service Company of Oklahoma ("PSO" or "Company") filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. Mr. Chaplin testified that PUD reviewed the Application, as well as the testimony and sponsored exhibits of Company witnesses. In addition, Mr. Chaplin reviewed prior testimony and sponsored exhibits from Cause No. PUD 201500208, data requests and responses, and conducted onsite audits at the Company's division office in Tulsa, Oklahoma. Mr. Chaplin testified that after review of SPP Fees and Expenses, IPP Credits and Interest, and Amortization of Severe Storm Expense, he recommended the Commission accept the following adjustments:

- PSO's proposed H-02-28 adjustment to operating income related to PSO's SPP Fees and Expenses, which is a reduction to rate base in the amount of ($25,242,886);

- PSO's proposed B-03-1 adjustment to rate base related to PSO's IPP System Upgrade Credits, which is a reduction to rate base in the amount of ($1,050,066);

- PSO's proposed H-02-10 adjustment to operating income related to PSO's Interest due on IPP System Upgrade Credits, which is an increase to rate base in the amount of $36,752; and

- PSO's proposed H-02-31 adjustment to operating income related to the amortization of severe storm expenses over a four-year period, which includes the amount approved for recovery in PUD Cause No. 201300217 that PSO has yet to collect. Adjustment H-02-31 increases rate base by $5,202,492.

Finally, Mr. Chaplin testified that he believes these recommendations are fair, just, reasonable, and in the public interest.

JOHN WALKUP

John Walkup is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In this Cause, Mr. Walkup presented PUD's recommendation for his assigned areas in response to the

Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

On September 21, 2017, Mr. Walkup filed Responsive Testimony for areas including: PSO's Internal Audit Reports, Cash Working Capital, Deferred Income Tax, Property / Ad Valorem Tax Expense, Factoring Expense, Interest Synchronization, and Income Taxes.

Mr. Walkup testified that PUD reviewed the Application, direct testimonies, schedules, workpapers, and sponsored exhibits filed by the Company. In addition, PUD reviewed PSO's prior workpapers, testimonies, and sponsored exhibits, along with Final Order No. 657877 for Cause No. PUD 201500208 and Final Order No. 639314 for Cause No. PUD 201300217. PUD also reviewed the data requests and responses issued by interveners. Lastly, PUD conducted an onsite audit at the Company's division office in Tulsa, Oklahoma. During the onsite audit, PUD reviewed confidential information and conducted interviews with Company witnesses who manage and perform the functions under review. Mr. Walkup testified that PUD recommends the Commission accept the following adjustments:

- **Accumulated Deferred Income Tax**: PUD recommends an adjustment to update Accumulated Deferred Income Tax to the six-month post test year balance at June 30, 2017. PUD's recommended adjustment will increase Accumulated Deferred Income Tax, resulting in a decrease to rate base of ($39,357,904).

- **Cash Working Capital**: PUD recommends an adjustment to Cash Working Capital ("CWC") to reflect all of PUD's recommended changes to the accounts included within the CWC calculation. PUD's recommended adjustment will increase PSO's pro forma Cash Working Capital included in rate base by $1,568,553.

- **Property / Ad Valorem Tax Expense**: PUD recommends an adjustment to current Property / Ad Valorem Taxes to reflect PUD's recommended adjustments to the net plant in service as of the six-month post test year, June 30, 2017, resulting in a decrease of ($49,673). Additionally, PUD recommends the Commission maintain its historical ratemaking treatment instead of allowing a modification to the Tax Adjustment Rider.

- **Factoring Expense**: Factoring Expense is expense associated with the collection of billed revenue and is determined based upon the Company's revenue. PUD recommends decreasing the Factoring Expense in the amount of ($999,441).

- **Interest Synchronization**: PUD recommends an adjustment to interest expense within the income tax calculation to reflect changes to the rate of return and rate base. Interest synchronization is a method that provides an interest expense deduction for regulatory income tax purposes equal to the ratepayers' contribution to PSO for interest expense coverage. PUD recommends an adjustment for interest synchronization in the amount ($359,544). The effect on the Revenue Requirement is included below, in the Current Income Tax Expense recommended adjustment.

- **Current Income Tax Expense**: PUD recommends an adjustment to reduce the PSO pro forma Current Income Taxes. PUD recommended net adjustments decreasing PSO's pro forma operating income before income taxes, and therefore, the income taxes are reduced. PUD's recommended adjustment to Current Income Tax Expense is a reduction of ($14,532,958).

Mr. Walkup did not propose any adjustments based upon his review of Internal Audit Reports or the area of Investment Tax Credits. Mr. Walkup testified that PUD believes the recommendations in this Testimony are just, fair, and reasonable and balance the interest of both the Company and its ratepayers.

James E. Mitschke II

James E. Mitschke is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In this Cause, Mr. Mitschke presented PUD's recommendation for his assigned areas in response to the Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

On September 21, 2017, Mr. Mitschke filed Responsive Testimony for the following areas: Quality of Service, Advanced Metering Infrastructure ("AMI") Adjustment, and the American Electric Power Service Corporation ("AEPSC") Adjustment.

Mr. Mitschke testified that PUD reviewed previous Commission orders, rules, issued data requests, reviewed data requests and responses, and conducted onsite audits at the Company's division office in Tulsa, Oklahoma. Mr. Mitschke testified that PUD's overall recommendation was that the Commission accept the following proposed adjustments made by the Company:

- PSO's proposed AMI Adjustment – decrease in Cost of Service ($504,127)
- PSO's proposed AEPSC Adjustment – decrease in Cost of Service ($5,104,160)

Mr. Mitschke testified that PUD supports these adjustments because they are year end true-ups, remove incentive programs from Cost of Service, remove one-time charges, and remove other expenses such as lobbying and aviation costs. Mr. Mitschke testified that this recommendation is fair, just, reasonable, and in the public interest.

Jeremy K. Schwartz

Jeremy Schwartz is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Audit Coordinator. Mr. Schwartz filed Responsive Testimony in Public Service Company of Oklahoma's ("PSO" or "Company") Cause No. PUD 201700151 on September 21, 2017, regarding PUD's accounting adjustments and the level of a decommissioning cost escalation factor if the Commission adopted the use of one.

Mr. Schwartz reviewed all information and testimony provided by the Company in this Cause. Mr. Schwartz further reviewed Commission orders, testimony related to areas in prior causes, and workpapers relating to PSO. Mr. Schwartz communicated with the Company through email, phone calls, in-person reviews, and electronic information/data requests and reviewed responses to these requests.

Mr. Schwartz recommended that the Commission accept PUD's adjustments and overall revenue requirement increase of $132,094,468. Further, Mr. Schwartz recommended that if the Commission chose to adopt the use of an escalation factor for decommissioning costs, it should utilize 1.6%.

Mr. Schwartz believes these recommendations are fair, just, and reasonable to both the Company and its ratepayers.

McKlein Aguirre

McKlein Aguirre is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst and filed Responsive Testimony on September 21, 2017, in Cause No. PUD 201700151. The purpose of Mr. Aguirre's testimony was to present PUD's recommendation pertaining to cost recovery of expenses included in Advertising, Reclassify Advertising Expense, Marketing and Sales Expense, Informational / Instructional / Miscellaneous / Sales Expense, Dues and Donations, and Credit Line Fees Expense in response to the Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

Along with reviewing the Application, associated testimonies, schedules, statutes, and Commission rules, Mr. Aguirre testified that he also issued a data request, reviewed responses to data requests, and conducted two onsite audits at the Company's division office in Tulsa, Oklahoma.

After conducting a thorough review of the Application, associated testimonies, schedules, statutes, and Commission rules, Mr. Aguirre testified that he recommends the Commission accept PSO's proposed adjustment No. WP H-2-27 to decrease PSO's cost of service by $173,678, PUD's adjustment No. H-2 to decrease Dues and Donations by $117,876, and PSO's proposed $678,104 adjustment No. WP H-2-9 to reclassify Credit Line Fee Expense to Administrative and General Expense. Finally, Mr. Aguirre testified that the recommended adjustments are fair, just, reasonable, and in the public interest.

Kathy Champion

Kathy Champion is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Senior Regulatory Analyst. Ms. Champion filed Responsive Testimony in Public Service Company of Oklahoma's ("PSO" or "Company") Cause No. PUD 201700151 on September 21, 2017, to present PUD's review of the Company's Application for a change or modification to its rates, charges, and tariffs, specifically regarding certain revenue and expense adjustments proposed by the Company.

Ms. Champion reviewed the Application, testimony, sponsored exhibits, and workpapers of Company witnesses in this Cause, as well as Commission orders and testimony related to areas in prior causes. In addition, Ms. Champion issued data requests, reviewed data requests and responses, conducted an onsite audit at the Company's division offices in Tulsa, Oklahoma, and had multiple conversations with Company personnel.

Ms. Champion recommends the Commission accept the adjustments made by the Company related to the Demand Program Expense, the Provision for Refund revenue adjustment, and all of the base rate adjustments except for the Proforma Adjustment related to Energy Efficiency ("EE")/Demand Response ("DR") Programs. PUD recommends the Commission remove the EE/DR portion of $2.7 million from the Proforma Adjustment. Instead PUD recommends that the Company provide additional information related to the need for the EE/DR adjustment and the effect that the adjustment would have in the Demand Side Management Rider to be filed in compliance with the Final Order in this Cause.

Ms. Champion believes these recommendations are fair, just, and reasonable and in the public interest.

KIRAN PATEL

Kiran Patel is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission"), and filed Responsive Testimony on September 21, 2017, in Cause No. PUD 201700151, filed by Public Service Company of Oklahoma ("PSO" or "Company"). The purpose of her testimony was to present PUD's recommendations regarding areas assigned in this Cause for an adjustment in the Company's rates and charges and the electric service rules, regulations, and conditions of service for electric service in the State of Oklahoma for the 12 months ended December 31, 2016.

On June 30, 2017, PSO filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. Ms. Patel reviewed the Application, as well as the testimony, sponsored exhibits of Company witnesses, schedules, statutes, and rules. In addition, Ms. Patel issued data requests, reviewed data requests and responses, and conducted onsite audits at the Company's division office in Tulsa, Oklahoma.

Ms. Patel testified that after the review of Materials, Supplies, and Fuel Inventories, Prepayments Expense, and Off-System Trading Deposits, Ms. Patel updated the six-month post test year average balances, which resulted in the following PUD adjustments: Adjustment No. B-4, to decrease Materials and Supplies by ($3,296,616); Adjustment No. B-5, to increase Fuel Inventories by $289,913; Adjustment No. B-6, to decrease Prepayments Expense by ($344,729); and Adjustment No. B-7, to increase Off-System Trading Deposits by $84,403.

Ms. Patel does not recommend any adjustments to the following items: Off-System Sales Margin and Revenue, Fuels and/or Purchased Power, Revenue Adjustment, and Fuel- Related Operation and Maintenance Expenses.

Ms. Patel believes that the recommendations are fair, just, and reasonable, and in the public interest.

CAROLYN J. WEBER

Carolyn Jean Weber is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In this Cause, Ms. Weber presented PUD's recommendation for her assigned areas in response to the Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

On September 21, 2017, Ms. Weber filed Responsive Testimony for the following areas: Generation Fleet Life Spans; 4/13/2017 Demolition Study; Regulatory Assets for the Non-Advanced Metering Infrastructure ("AMI") Meters, Deferred Accounting of Environmental Improvements, and Retirement of Northeastern Unit 4 ("NE 4"); Accumulated Depreciation and Amortization; Asset Retirement Obligations ("AROs") and related Gains and Losses on ARO Settlements; 12/31/2016 Depreciation Study; and Depreciation, Amortization, and Accretion Expenses.

Ms. Weber testified that PUD reviewed previous Commission orders and rules, issued data requests, reviewed data requests and responses, and conducted onsite audits at the Company's division offices in Tulsa, Oklahoma. Ms. Weber also reviewed relevant portions of applications, testimonies, and orders related to assigned areas in this Cause that were included in Cause Nos. PUD 200600285, PUD 200800144, PUD 201000050, PUD 201300217, and PUD 201500208. She also reviewed the FERC Form 1 for the years ended December 31, 2015, and December 31, 2016, for information in the notes or schedules, and reviewed the PSO Form 10-K at the Securities and Exchange Commission ("SEC") website for the years ended December 31, 2015, and December 31, 2016. PUD reviewed the monthly trial balances submitted by PSO through June 30, 2017, in order to determine the accuracy of the amounts reported in the Application and Updated Schedules and Workpapers. Ms. Weber testified that the recommendations made by PUD are fair, just, reasonable and in the public interest. She testified that PUD's overall recommendation was that the Commission accept the following adjustments:

Adj. No.	Description – Adjustment to Rate Base	Increase to Rate Base	Decrease to Rate Base
B-9	Reclassify Unrecovered Plant (NE 4) from Accumulated Depreciation to Regulatory Asset	$ 84,514,703	$ (84,514,703)
B-10	NE 4 - Regulatory Asset (Acct 1823377) - Update to 6/30/17	$ -	$ (1,774,952)
B-11	Accumulated Depreciation (Acct 1080001) and CWIP in Service - Update to 6/30/17	$ 218,460	$ (24,060,930)
B-12	RWIP - Project Detail (Acct 1080005) - Update to 6/30/17	$ -	$ (667,407)
B-13	A/P for Amortization of Plant (Acct 1110001) - Update to 6/30/17	$ -	$ (5,947,916)
B-14	ARO Liability (Acct 2300001) - Update to 6/30/17	$ -	$ (1,361,222)
B-15	Deferred Environmental (Acct 1823552) - Correct 12/31/16 Balances	$ 13,082,073	$ -
B-16	Deferred Environmental (Acct 1823552) - Reverse Half Year 2018 Amortization	$ 968,689	$ -
B-17	Deferred Environmental (Acct 1823552) - Correct Company Exhibit Errors	$ 531,524	$ -
B-18	Deferred Environmental (Acct 1823552) - Remove Carrying Costs through 6/30/17	$ -	$ (1,139,884)
B-19	Deferred Environmental (Acct 1823552) - Remove Estimated Costs 7/1/17 through 12/31/17	$ -	$ (12,738,287)
B-20	Non-AMI Meters (Acct 1823223) - Update to 6/30/17	$ -	$ (7,773,107)

Adj. No.	Description – Adjustment to Revenue Requirement	Increase to Rev Req	Decrease to Rev Req
H-5	Amortization of Intangible Plant Account 4040001 - Update to 6/30/17	$ 6,750,019	$ -
H-6	Disallow portion of 6/30/17 Update to Amortization Expense Account 4040001 on Fully Amortized Intangibles	$ -	$ (758,426)
H-7	Decrease Regulatory Debits Expense in Account 4073000 to Correct Non-AMI Meter Amortization Rate	$ -	$ (2,219,213)
H-8	Disallow PSO Pro Forma Adjustment for Unrecovered Reserve	$ -	$ (313,063)
H-9	Decrease Production Ad Valorem Taxes Account 4081005 for Adjustments to Regulatory Asset for Environmental Deferred Accounting Amortization	$ -	$ (66,171)
H-9	Decrease Production Depreciation Expense Account 4030001 for Adjustments to Regulatory Asset for Environmental Deferred Accounting Amortization	$ -	$ (102,664)
H-9	Decrease Production Regulatory Debits Account 4073000 for Adjustments to Regulatory Asset for Environmental Deferred Accounting Amortization	$ -	$ (440,328)
H-10	Decrease Accretion Expense in Account 4111000 to Move Accretion on Fully Accrued AROs to be Below-the-Line	$ -	$ (384,376)
H-11	Decrease Production Depreciation due to PSO's extension of the useful life of the Oklaunion ARO from 2020 to 2046	$ -	$ (1,380,888)
H-12	Depreciation Update 6/30/17 Per 8/24/17 Schedule I Using PUD Depreciation Rates	$ -	$ (10,023,411)
H-13	Record NE 4 Regulatory Asset Amortization Account 4073000	$ 3,543,809	$ -
H-14	Record NE 4 Cost of Removal Reserve Amortization Account 4073000	$ 61,560	$ -
H-15	Disallow PSO Pro Forma Adjustment to remove Gain on Disposal - H-2-33	$ -	$ (50,192)

AMY TAYLOR

Amy Taylor is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In this Cause, Ms. Taylor presented PUD's recommendation for her assigned areas in response to the

Application filed on June 30, 2017, by Public Service Company of Oklahoma ("PSO" or "Company").

On September 21, 2017, Ms. Taylor filed Responsive Testimony for the following areas:

- Bad Debt Expense;
- Lease / Rent Expense;
- Miscellaneous General Expense;
- Corporate Expense / Overhead and Allocations;
- Medicare Part D Subsidy Regulatory Asset;
- Employee Insurance Expense;
- Insurance / Self Insurance Expense;
- Injury and Damage Expense; and
- Miscellaneous Revenue.

Ms. Taylor testified that PUD reviewed previous Commission orders, rules, issued data requests, reviewed data requests and responses, and conducted multiple onsite audits at the Company's division office in Tulsa, Oklahoma. Ms. Taylor testified that PUD's overall recommendation is that the Commission accept the following adjustments, as proposed by PSO:

- Bad Debt Expense – increase of $160,993;
- Miscellaneous General Expense – increase of $633,618;
- Medicare Part D Subsidy Regulatory Asset – increase of $3,919,320;
- Employee Insurance Expense – increase of $703,490;
- Miscellaneous Revenue – decrease of ($5,303,001).

The total net effect of PSO's proposed adjustments is a decrease in Operating Income of ($10,720,422).

Ms. Taylor believes these proposals are fair, just, and reasonable to both the Company and its ratepayers.

JEFFERY DUNSWORTH

Jeffrey Dunsworth is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. Mr. Dunsworth filed Responsive Testimony on September 21, 2017, in Cause No. PUD 201700151. The purpose of his testimony was to present PUD's recommendations pertaining to the following areas: Weather Normalization; Regulatory Expense; Large Invoices Excluding Cost of Gas; Fuel, Purchased Power, and Taxes; and Outside Services/Attorney Fees, in response to the Application filed by Public Service Company of Oklahoma ("PSO").

After onsite audits; PUD's review of the Application, testimonies, and workpapers; review of statutes and rules; review of Data Requests; and recalculation of the various expenses including invoices to determine accuracy of the adjustments, PUD recommends the Commission accept the adjustments as proposed by PSO for Weather Normalization, Regulatory Expenses, Large Invoices Excluding Cost of Gas, Fuel, Purchased Power, and Outside Services/Attorney Fees. PUD believes that these recommendations are fair, just, reasonable, and in the public interest.

GEOFFREY M. RUSH

On June 30, 2017, PSO filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. Mr. Rush reviewed the Application, as well as testimony, sponsored exhibits of Company witnesses, schedules, statutes, and rules. In addition, Mr. Rush issued data requests, reviewed data requests and responses, and conducted onsite audits at the Company's division offices in Oklahoma City and Tulsa, Oklahoma.

The items specifically analyzed in his testimony were as follows: Return on Equity ("ROE"), Cost of Debt, Capital Structure, Payroll Expense, Long-Term and Short-Term Incentive Compensation, and Pension Expense. Additionally, his testimony outlined all of the areas that PUD reviewed.

PSO's cost of capital is comprised of two components: debt and equity. While fixed, contractual interest payments determine the cost of debt, the cost of equity must be estimated through financial models and other analysis. Mr. Rush employed three financial models on a group of similar proxy companies to arrive at an estimate of the Company's cost of equity in this Cause, including: 1) the Discounted Cash Flow Model; 2) the Capital Asset Pricing Model; and 3) the Comparable Earnings Model. In addition, Mr. Rush added a market analysis to review the returns of utility fund companies, compared to the market as a whole. Finally, Mr. Rush conducted a market analysis to determine the Company's optimal capital structure.

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the dividend discount model, which maintains that the value of a security is equal to the present value of the future cash flows that it generates. The average DCF result for the proxy companies using the Quarterly Approximation DCF model was 8.53%. The Capital Asset Pricing Model ("CAPM") is a market-based model where investors require higher returns for adding additional risk. The average CAPM result for the proxy companies was 6.38%. The Comparable Earnings Model ("CEM") involved averaging the earned returns on equity of other utility companies. The composite average and result of the CEM was 10.08%. The market analysis looked at 14 of the top utility funds and compared the returns over a 3-year, 5-year, and 10-year time span. The average market analysis result, using the 10-year time span, was 6.60%. Mr. Rush's recommended ROE is 8.90%, which is the highest point in a range of reasonableness as determined by Mr. Rush.

Capital Structure refers to the way a firm finances its overall operations through external debt and equity capital. Mr. Rush recommended the Company's proposed debt ratio of 51.5% debt and 48.5% equity because it is the Company's actual debt ratio. Additionally, Mr. Rush recommends PSO's proposed cost of debt of 4.60% because it is the Company's actual debt.

The Company had requested $12,488,266.48 in Short-Term Incentive Compensation, and $4,345,963.14 in Long-Term Incentive Compensation. Mr. Rush recommended that the

Commission allow 100% of Short-Term Incentive Compensation in the amount of \$12,488,266.48, and allow 25% of Long-Term Incentive Compensation in the amount of \$1,086,491, disallowing the remaining 75% of Long-Term Incentive Compensation in the amount of \$3,259,472. The Company's compensation plan was comprehensive, and included both short-term and long-term incentives. The allowance of 100% of short-term incentives and 25% of long-term incentives is appropriate to include in the overall compensation package of PSO and its recovery from consumers. Mr. Rush believed that both short-term and long-term incentives are an important part of employee retention, as the programs require continuous employment to receive the full benefit of incentive compensation.

Mr. Rush requested the Commission accept the following recommendations because they are fair, just, reasonable and in the public interest:

1. A cost of equity of 8.90%, which is the highest point in a range of reasonableness between 6.90% and 8.90%.
2. A cost of debt of 4.60%, as proposed by the Company.
3. A capital structure consisting of 51.5% debt and 48.5% equity.
4. A decrease adjustment in the amount of \$3,259,472 to reduce incentive compensation.
5. The Company's proposed increase adjustment to Payroll Expense in the amount of \$2,727,075.
6. The Company's proposed increase adjustment to Pension Expense in the amount of \$92,361,841.

<u>Attorney General</u>

EDWIN C. FARRAR

Mr. Edwin C. Farrar pre-filed responsive testimony on behalf of the Attorney General of the State of Oklahoma. He testified as to his educational and professional background as a Certified Public Account. He has testified previously before the Oklahoma Corporation Commission and his qualifications as an expert have been accepted. Mr. Farrar recommended certain adjustments to rate base and to the operating income statement of Public Service Company of Oklahoma ("PSO").

Mr. Farrar testified regarding the impact of costs that PSO included in this case that were incurred by PSO in order to comply with federal environmental mandates. He testified that the costs associated with PSO's environmental compliance plan, as approved by the Commission in the prior PSO rate case, Cause Number PUD 201500208, constitute a significant portion of PSO's requested rate increase. Specifically, Mr. Farrar testified that the overall costs of the plan in this case total \$280 million, representing \$43.7 million of PSO's requested rate increase, based on PSO's requested depreciation rates and return on equity.

Mr. Farrar recommended that rate base be updated for known and measurable changes known to occur six months after the end of the test year as required by statute, which requires an update from December 31, 2016 to June 30, 2017. These adjustments include plant in service, accumulated depreciation, prepayments, fuel and materials and supplies inventories, customer deposits, regulatory assets and liabilities, and accumulated deferred income taxes. Mr. Farrar recommended a net reduction to rate base of $70,410,589 for those adjustments.

Mr. Farrar recommended that part of PSO's prepaid pension asset be excluded from rate base because PSO could not provide support for the starting, 2003 balance of $36,508,316. Mr. Farrar stated that a review of the Direct Testimony of John O. Aaron from Cause Number PUD 200300076 stated the balance was zero. Mr. Farrar also testified that one purpose of a pension fund is to produce sizable earnings, and that those earnings reduce pension expense. For that reason, the totals of the pension expense and the pension fund balance will not equal each other until the pension plan is ended. Mr. Farrar explained that Mr. Hamlett made this difference appear worse by including the estimated pension fund earnings related to excess pension funding in his totals, even though ratepayers had been paying a return on those balances the entire period covered by Mr. Hamlett's analysis. Mr. Farrar also testified that the Commission had recognized pension expense based on the Company's pension contributions until the early 1990s, so that any prepaid pension asset from that period would represent a ratepayer asset, not a Company asset. For those reasons, Mr. Farrar recommends that the 2003 initial balance of $36,508,316 be excluded from the prepaid pension asset. This adjustment was included in Mr. Farrar six-month update adjustment.

Mr. Farrar testified that PSO's material and supplies inventory had decreased significantly beginning in December 2016, and continued to drop through the end of the six-month update period. Mr. Farrar based the pro forma adjustment of this working capital item on the average balance of the seven months from December 2016 through June 2017. This approach allows the Company to earn a return on a higher balance than the June 30, 2017 amount, providing the Company some allowance for normal fluctuations in inventory balances, while recognizing that inventory levels have been reduced. This adjustment was included in Mr. Farrar's six-month update adjustment.

Mr. Farrar also recommended an adjustment to the updated accumulated deferred income tax balance. On August 25, 2017, the Company provided a supplemental response to PUD JKS 1-3, which included a revision to the balance of accumulated depreciation at June 30, 2017. A substantial portion of accumulated deferred income taxes is related to depreciation rate differences between financial accounting and tax accounting. The downward revision of accumulated depreciation must be offset by a proportional increase in the balance of Accumulated Deferred Income Tax ("ADIT"), based on the combined state and federal effective income tax rates to avoid understating ADIT and overstating rate base. This adjustment was included in Mr. Farrar's six-month update adjustment.

Mr. Farrar recommended an adjustment to recognize an increase in revenue during the six-month statutorily required update period. PSO declined to provide updates for all components of its revenue adjustments. Specifically, the Company did not base the updated compliance revenue adjustment on updated billing determinants from a proof of revenue, as it did in its test year revenue adjustment. This change in methodology appears to be a problem, because PSO shows a decline in revenue, even when customer counts increased. This discrepancy was most glaring for the large customers in service levels one through three, where PSO's update resulted in a$4 million decline in revenue, even though these classes had a net increase in customers. After additional discovery was issued and discussions were held with the

Company, Mr. Farrar was provided enough information to base the compliance adjustment for the large customers on updated billing determinants. The Company did not provide updated billing determinants for the smaller customers in service levels four and five. A revenue adjustment was calculated using the Company's revenue update, corrected for the billing determinants for the larger customers, which increases the Company's pro forma Oklahoma retail revenue by $505,152. Mr. Farrar also recommended that the Commission require the Company provide an update to revenue to June 30, 2017, using the same methodology used in PSO's original filing, and to provide all parties an opportunity to review and respond to those updates.

Mr. Farrar recommended several adjustments to operating expenses, including payroll, incentive compensation, nonqualified retirement plans, property taxes, generation expenses, and transmission expenses. He testified that payroll-related expenses should be adjusted to levels as of June 30, 2017. Mr. Farrar issued discovery requesting an update to PSO's payroll annualization adjustment, but the response included payroll increases beyond the statutory update period. Mr. Farrar explained that including selective cost increases beyond the six-month statutory update period would unfairly reflect cost increases and ignore offsetting cost decreases. Mr. Farrar found that the estimated increased payroll cost exceeded levels generally reported for the industry. Mr. Farrar prepared an analysis of PSO's actual payroll costs from PSO's last two rate cases, and compared them to the test year expense reported in this rate case. Mr. Farrar found that PSO's payroll costs increased less than what the Company estimated in those previous rate cases, and even decreased since PSO's most recent rate case, PUD 201500208. Mr. Farrar also reviewed PSO's projected payroll increases from the two previous PSO rate cases, and found that the Company had significantly overstated PSO's payroll cost increase in each of those cases. Mr. Farrar then reviewed data from the Bureau of Labor Statistics ("BLS") and found that the index for utility salaries and wages had increased at an annual rate of 3.07% from June of 2016 to June of 2017, and recommended that the Commission utilize the BLS value to adjust PSO's payroll. Mr. Farrar recommended the annualization of payroll expenses to June 31, 2017 based on the annual reasonable increase rate, which reduces PSO's requested total company payroll cost by $1,113,416, and reduces the related payroll taxes by $76,973.

Mr. Farrar also recommended that the Commission adopt the adjustments it has made in previous rate cases related to short-term incentive compensation programs that are of limited benefit to ratepayers. Mr. Farrar testified that the majority of the funding level of this form of compensation rewards employees for high Company earnings, which have limited benefits for ratepayers. Mr. Farrar recommended the Commission exclude one-half of the annual incentive plan costs as it has done in recent rate cases. The adjustment to share one-half of the target level of the annual incentive plan expense reduces operation and maintenance expenses by $4,549,440, and reduces the related payroll taxes by $314,514.

Mr. Farrar also recommended the Commission follow its policy of excluding all of PSO's long-term incentive compensation from PSO's revenue requirement, because PSO's long-term incentive compensation plan is financial in nature, designed to increase the Company's earnings regardless of how that is achieved. Mr. Farrar recommended an adjustment to exclude the cost of PSO's long-term incentive compensation plan from rates, which reduces the total company revenue requirement by $3,634,761.

Mr. Farrar also testified that the cost of the non-qualified pension plans be excluded from rates because this type of indirect compensation for highly paid executives is unnecessary in order to provide electric service to customers. The adjustment to exclude the non-qualified pension costs from rates reduces the total company revenue requirement by $342,246 for both PSO and American Electric Power Service Company.

PSO had proposed an adjustment to increase generation operation and maintenance expenses to a three-year average of those expense, adjusted for the retirement of Northeastern Unit 4. Mr. Farrar testified that the adjusted generation expenses decrease continually throughout the three-year period. The adjusted expense level was: $82,924,248 in 2014; $81,149,291 in 2015; and $78,871,294 in 2016. This is not an example of fluctuating expense levels, but instead of a trend. It is clear the generation operation and maintenance expense has been declining in recent years. PSO provided no other support for its contrary upward adjustment. Therefore, Mr. Farrar recommended that PSO's generation expense adjustment be reversed. This adjustment reduces expenses by $2,110,317.

PSO included an adjustment to increase transmission operation and maintenance expenses for Southwest Power Pool Schedule 9 Network Integration Transmission Service by $13,994,625. PSO provided no support or explanation for this increase, and the requested level significantly exceeds past levels for this expense. Mr. Farrar recommend that this expense be limited to the test year amount, unless and until PSO provides sufficient documentation to verify that the Company will sustain a higher expense level. This adjustment reduces transmission operation and maintenance expenses by $13,994,625.

Mr. Farrar testified that ad valorem tax expense should be updated to June 30, 2017, as required by statute, and consistent with the update of plant in-service to that date. This adjustment decreases the total company ad valorem taxes by $49,671.

Mr. Farrar discussed the potential impact of substantial plant investment included in this rate case on ratepayers, and ways that the Commission can reduce that impact. Mr. Farrar also discussed how a large asset's impact on rates is reduced over time, noting that the increase in nominal earnings of most ratepayers could also make the cost of a given asset more affordable in the future. Mr. Farrar identified some actions that the Commission can take to reduce the immediate impact of large asset additions that will dramatically increase rates if approved by the Commission.

Mr. Farrar noted that the Commission should first make sure all costs included in the revenue requirement are absolutely essential at the level requested for the provision of utility service. Once the Commission has ensured the necessity of the costs to be recovered from ratepayers, Mr. Farrar identified three mitigation strategies that the Commission could employ to allow ratepayers more time to adjust to higher rates, if approved by the Commission. Mr. Farrar recommended that one option would be to require a utility to use debt financing for large rate base additions, and in the absence of that, to apply a comparable debt return to that portion of rate base represented by the new asset. Mr. Farrar also suggested a second mitigation strategy in the form of a deferral of depreciation recovery. This method would provide an immediate cost of capital recovery for the asset, but would delay depreciation a few years, allowing ratepayers time to adjust to the new, higher rates. Finally, Mr. Farrar suggested that the Commission could phase-in any rate increase it approves in stages spread over a few years.

Mr. Farrar testified that the impact of adjustments recommended by all witnesses for the Attorney General reduced PSO's requested rate increase by a total of $86,369,736.

Marlon F. Griffing

Dr. Marlon F. Griffing submitted pre-filed responsive testimony on behalf of Mike Hunter, Oklahoma Attorney General. In his testimony, Dr. Griffing provided a recommendation of 8.83 percent for the return on equity of Public Service Company of Oklahoma ("PSO" or "the Company") after the application of accepted models to a comparison group of regulated electric utilities. Dr. Griffing also reviewed and provided critiques of PSO's cost of capital analysis and addressed other claims by the Company relevant to cost of capital.

Dr. Griffing also provided an exhibit showing his educational and professional qualifications to testify regarding cost of capital. Dr. Griffing received his Ph.D. in economics from the University of Nebraska at Lincoln and has 19 years' experience as an analyst in utility regulation. He has served as an analyst at the Nebraska Public Service Commission and at the Minnesota Department of Commerce, also working as a consultant at several firms before joining PCMG & Associates Inc. in 2015. Dr. Griffing testified that the firm has professional staff with expertise in economics, accounting, and cost analysis.

1. Cost of Capital Principles

Dr. Griffing began his testimony by explaining the role of cost of capital determinations in public utility regulation. He explained that public utility regulation requires setting a cost of capital because the lack of competition in utility industries prevents markets from ensuring the most economically efficient outcome. Public utilities lack effective competition and thus have natural monopoly status for several reasons, including high fixed costs, declining average costs, and legal obstacles.

He testified that the guiding legal test for assessing regulatory cost of capital was set out in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). He noted that Hope provides three factors for assessing cost of capital: 1) whether the firm would have comparable earnings compared to firms of similar risk, 2) whether it ensures the financial integrity of the firm, and 3) whether the firm can attract capital necessary for additional investment. Dr. Griffing testified that his analysis satisfies this test by analyzing companies with risks similar to PSO and determining the return on equity indicated by market prices for those companies. His return on equity recommendation can then be combined with PSO's capital structure and cost of debt to determine its overall cost of capital.

2. Comparison Group

Dr. Griffing developed a comparison group to serve as the set of companies having similar risks and characteristics to PSO. He started with a pool of electric utility companies identified by Value Line and then applied various screening conditions to ensure the firms were sufficiently similar to PSO. Dr. Griffing's screens, he explained, included the following: being publicly traded; have operations primarily in the continental United States; showing a stable record of paying dividends; not being involved in any mergers or acquisitions; having a Standard Industrial Classification code indicating electricity is the main activity of the firm; having regulated electricity operations as the primary source of income and revenue; having a Standard & Poor's credit rating between BBB and A+, and having positive growth-rate projections based on expert analysis. Dr. Griffing identified twenty-four companies meeting his screening conditions out of the original pool of Value Line electric utility firms.

3. Discounted Cash Flow Analysis

The primary method used by Dr. Griffing to estimate return on equity is the discounted cash flow ("DCF") analysis, which can derive a rate of return by combining dividend yields at current market prices with various estimates of earnings growth. Dr. Griffing explained that he used the constant growth DCF model, which models earnings growth continuing at a set rate forever. He testified that his growth assumption was derived from the five-year growth estimates of equity analysts set out in three sources: Zacks Investment Research, Thomson Financial Network via Yahoo! Finance, and Value Line. Dr. Griffing collected growth estimates for each company in the Comparison Group during June, July, and August and calculated the mean of the growth rate from each source.

Dr. Griffing calculated the dividend yield component of DCF starting with current dividend payments from Value Line and Zacks during June, July, and August. In order to reduce the impact of short-term price movements, he calculated a four-week mean price using pricing data from Yahoo! Finance from July 24 to August 18. He then calculated a dividend yield assuming growth in the dividends throughout the following year. Combined with the growth rate assumption for each company, Dr. Griffing derived a return on equity for each firm.

Dr. Griffing noted that he performed an additional screen on the comparison group after these initial steps with the DCF analysis. He removed any companies with an abnormally low return on equity implied by the results, explaining that if a company was not earning an amount at least equivalent to PSO's highest yield debt instrument plus about 250 basis points, it would not be competing with PSO for investment capital. The screening condition eliminated four more companies from the comparison group, leaving twenty companies.

The DCF analysis applied to the remaining companies produced an average growth rate of 5.54 percent and dividend yield of 3.29 percent, together providing a return on equity estimate of 8.83 percent, Dr. Griffing testified. He also performed a multi-stage DCF analysis to estimate how a lower long-term growth rate would impact the return on equity estimate. He used long-term growth estimates of gross domestic product, a measure of economic activity, published by the Congressional Budget Office in June 2017. The estimate was 4.0 percent.

Applying this assumption to a multi-stage DCF model, Dr. Griffing found the return on equity estimate would be reduced to 8.23 percent. He also applied the assumption of 4.2 percent gross domestic product growth provided by PSO's expert witness Michael Vilbert, which resulted in a return on equity of 8.30 percent.

4. Reviewing Reasonableness

In order to assess the reasonableness of his DCF analysis, Dr. Griffing performed additional analysis with the Capital Asset Pricing Model ("CAPM") and reviewed the returns on equity granted recently in other jurisdictions. He explained that while the DCF model provides the best estimate of return on equity because it incorporates investor beliefs with the least judgment required, reviewing other material can be informative as to whether DCF results are reasonable.

a. Capital Asset Pricing Model

The CAPM theorizes, as Dr. Griffing explained, that investors can diversify out of being impacted by company-specific risk by investing a larger pool of investments such as the market portfolio, or all stocks available for investment. He testified that, in doing so, investors must still take on "systematic risk." The CAPM theorizes that specific companies are exposed to systematic risk in varying degrees, measured by the correlation of companies' price movements to the changes in price of the broader market, Dr. Griffing explained. He noted that this measure of correlation is called "beta" (ß).

The CAPM also theorizes, however, that investors could avoid exposure to systematic risk by investing in a risk-free asset such as a government bond, Dr. Griffing testified. Thus, he explained that the CAPM derives the existence of a market risk premium that represents the return earned by investing the market portfolio minus the return that could have been earned by investing in a risk-free asset. He also stated that, since beta measures exposure to systematic risk, the CAPM postulates that a stock showing greater beta can also be expected to earn a higher risk premium. A lower beta, on the other hand, implies a lower risk premium, he noted.

Dr. Griffing applied the CAPM to estimate PSO's return on equity by calculating an estimated return on equity for the comparison group. As his measure of the risk-free rate, he testified that he would normally recommend the yield on Treasury securities maturing in five years. Longer-maturity debt securities contain inflation risk, while shorter-term debt securities have significantly lower returns owing to the short-term planning horizon implied by their maturities. To reduce the impact of historically low interest rates, however, he chose to use 30-year Treasury Bonds. Using yield data from July 24 to August 18, 2017, Dr. Griffing derived a risk-free rate of return on 2.84 percent.

The market risk premium Dr. Griffing developed was calculated by reviewing the broad stock market's current dividend yields as well as analyst estimates of the market's appreciation potential over three to five years. He relied on Value Line material to provide these measures, finding a 2.1 percent dividend yield and an appreciation potential over three to five years of 35 percent. Dr. Griffing annualized the market's appreciation potential over four years which, combined with the dividend yield, resulted in estimated market returns of 9.89 percent. After removing the risk-free rate, Dr. Griffing calculated the market risk premium to be 7.05 percent.

Dr. Griffing used Value Line's calculated betas for each company in the comparison group, then calculated a mean beta value of 0.71. Using the risk-free rate, market risk premium, and beta values he derived, the resulting CAPM return on equity estimate was 7.81 percent.

He also performed an "empirical CAPM" or ECAPM analysis, recognizing that historical beta values may understate forward-looking returns for companies with beta values under 1.00. Dr. Griffing performed this analysis in two ways: the x-factor method and the α-method. The results of Dr. Griffing's ECAPM analysis showed a range from 7.96 to 8.33 percent.

b. Authorized Returns on Equity

Dr. Griffing also reviewed the results of fully litigated rate cases in other jurisdictions to evaluate the reasonableness of his DCF analysis. He used information published in SNL's Regulatory Research Associates Regulatory Focus annual and quarterly reports. The reports contain summaries of regulatory proceedings, including authorized returns on equity. Dr. Griffing excluded cases that resulted from settlements since the resulting returns on equity may reflect trade-offs that do not comport with the strict application of ratemaking principles. He also limited his review to 2016 and 2017 to ensure the relevant market conditions reasonably match current conditions. Dr. Griffing found that, in 2016, authorized returns ranged from 8.64 percent to 10.00 percent with a mean of 9.43 percent and a median of 9.50 percent. He also found that, so far in 2017, authorized returns have ranged from 9.20 percent to 10.10 percent with a mean of 9.58 percent and a median of 9.50 percent.

c. Reasonableness Review

Overall, Dr. Griffing concluded that the results of his DCF analysis were supported by his application of the CAPM and his review of return on equity granted in other jurisdictions. The CAPM estimated the return on equity from 7.81 percent to 8.33 percent, showing the requirement was unlikely to be significantly higher than the DCF results. Likewise, his review of authorized returns showed that returns on equity can be somewhat lower than 9.00 percent without adversely impacting PSO's ability to attract capital.

5. Cost of Capital Recommendation

Dr. Griffing recommended that PSO be authorized a return on equity of 8.83 percent, the result of his constant-growth DCF analysis. He testified that the constant-growth DCF model relying on analyst estimates of growth rates provides the best estimate for regulation since it allows the least discretion over input assumptions. He testified that other models showed a range from 7.81 percent to 8.33 percent, supporting the conclusion that 8.83 percent provided adequate returns. He also noted that other jurisdictions had granted returns lower than 9.00 percent. He thus recommended a range from 8.83 percent to 9.00 percent.

To calculate the Company's overall cost of capital, Dr. Griffing reviewed PSO's proposed capital structure and historical cost of debt. He found that the Company's proposals were both reasonable, including its capital structure with debt of 51.5 percent and equity of 48.5 percent. Dr. Griffing calculated the overall cost of capital for PSO using his proposed return on equity as 6.65 percent.

6. Critique of Company Analysis

Dr. Griffing testified that the cost of capital analysis produced by the Company's witnesses suffers from several defects. Overall, however, he noted that PSO's analysis shares several similarities to his analysis. For example, he noted that his comparison group has significant overlap with Michael Vilbert's sample. He explained that the groups differed because Dr. Griffing applied screening conditions using Standard Industrial Classification code, stable records of dividend payments, and deriving most income and revenues from electric utility operations, which eliminated eight companies included in Dr. Vilbert's sample. On the other hand, Dr. Griffing explained, Dr. Vilbert's screening conditions eliminated four companies included in Dr. Griffing's comparison group.

Dr. Griffing noted that Michael Vilbert also employed constant-growth and multi-stage DCF analyses, estimating return on equity at 8.80 percent and 7.80 percent, respectively. Dr. Griffing testified that Dr. Vilbert adjusted his results for companies' leverage, however, which increased the range of his DCF results to 9.10 percent to 10.90 percent to support the Company's 10.00 percent recommended return on equity. Dr. Griffing explained that this adjustment likely accounts for more than 100 basis points of the difference between his and Dr. Vilbert's analyses.

Dr. Griffing recommended rejecting Michael Vilbert's leverage adjustment. Dr. Griffing explained that the adjustment uses market capitalization to derive companies' financial leverage, which is not appropriate because investors are already aware of firms' financial leverage. He explained that investors thus take leverage and financial risk into account when purchasing investments, meaning that the price movements of companies' stock reflect leverage. The resulting price movements are then reflected in the prices used in the DCF analysis as well as in the calculation of beta (ß) used in the CAPM.

Likewise, Dr. Griffing rejected Michael Vilbert's assumptions in the application of the CAPM. He noted that Dr. Vilbert used year-ahead estimates of debt security yields, further adjusted upward by Dr. Vilbert, to set the risk-free rate of return in an effort to mitigate the impact of rising interest rates resulting from the Federal Reserve raising the federal funds rate, a short-term lending measure. Dr. Griffing explained that Michael Vilbert's data from Blue Chip Economic Indicators was not reliable since it had been consistently wrong in predicted increases in interest rates since the beginning of the 2007 to 2009 economic crisis. He also noted that increases in the federal funds rate do not automatically impact long-term interest rates, which have actually declined over the last six months despite the federal funds rate increasing twice. Dr. Griffing further explained that investors can already take into account any expected increasing in prevailing rates when trading long-term debt securities.

Dr. Griffing also rejected Michael Vilbert's calculation of the market risk premium because of its use of long-term historical data. Dr. Griffing explained that return on equity should be calculated with forward-looking conditions while the use of historical data relies on relationships between interest rates, equity returns, and inflation that are not reflective of the near future.

7. Northeastern Unit 4 Risk Premium

Dr. Griffing addressed claims by PSO witnesses that disallowance of undepreciated costs of a single coal generation plant, Northeastern Unit 4, would require an upward adjustment to return on equity due to higher risk. Since the Company's witnesses produced no quantitative analysis of such an adjustment, Dr. Griffing testified that it might be estimated by reviewing the consequences on bond yields if the Company's credit rating were downgraded.

Dr. Griffing testified that actual disallowances of single coal generating plants had occurred in two recent cases in Ohio and Mexico, which were not followed by downgrades in credit ratings. Instead, he explained, the two firms' credit ratings eventually increased following removal of the generating plants from rate base, showing that factors besides disallowances affect the ratings. Dr. Griffing concluded that there is not sufficient evidence that disallowance of a single coal generating plant would require a risk premium adjustment to PSO's return on equity.

8. Regulatory Lag and Historical Test Year

Lastly, Dr. Griffing addressed claims by PSO witnesses that regulatory lag and the use of a historical test year had impacted PSO's ability to earn its authorized rate of return in recent years. He testified that PSO was asked in discovery how, exactly, regulatory lag and the use of a historical test year had impacted PSO, to which PSO's witnesses responded that the disallowance of incentive compensation expenses, ad valorem taxes, and payroll adjustments had impacted PSO's ability to earn its authorized rate of return. Dr. Griffing concluded that PSO appears to disagree with particular costs being disallowed, which is not a problem connected to regulatory lag or the use of a historical test year to set rates.

James B. Alexander

James B. Alexander submitted pre-filed responsive testimony on behalf of Mike Hunter, Oklahoma Attorney General. Mr. Alexander, a regulatory analyst employed by the Attorney General, testified regarding his qualifications as well as the request by Public Service Company of Oklahoma ("PSO" or "the Company") to increase storm damage recovery expenses included in the Company's base rates.

Mr. Alexander testified that his educational background and professional experience provide him with expertise in Southwest Power Pool protocols, power scheduling, and monitoring outage restoration. He stated that he received a Bachelor of Business Administration degree from the University of Oklahoma, where he studied energy management. He explained that he then worked at Invenergy, LLC, scheduling generation resources and coordinating outage restoration with power asset managers. Mr. Alexander testified that, after working at Invenergy, LLC, he worked at the Oklahoma Municipal Power Authority working on day-ahead and real-time generation scheduling, monitoring jointly owned generation units, managing exports and imports between regional markets in Oklahoma and Taxes, and coordinating distribution outage restoration.

Mr. Alexander explained the current regulatory treatment of PSO's storm damage recovery expenses. He noted that the Oklahoma Corporation Commission ("Commission") has allowed a $2.87 million base rate expense in cases since PSO's 2008 base rate case. However, he stated that PSO has been able to recover the actual storm damage recovery expenses by recording any difference as a regulatory liability (in the event of over-recovery) or as a regulatory asset (in the case of an under-recovery). He explained that the net balance would then be amortized over a period of several years during a subsequent rate case. This treatment continued in PSO's most recent rate case, Mr. Alexander explained.

He noted that PSO has requested that $9.8 million be included in the revenue requirement in this case as the amortization for past storm damage recovery expenses. He stated, however, that PSO has also requested that it be allowed to increase the base rate allowance from $2.87 million to $11.2 million. Mr. Alexander explained that the $11.2 million calculation is the result of a seven-year average of past storm damage expenses, and he noted that PSO is requesting that the same under and over-recovery rules be used with the new $11.2 million allowance.

Mr. Alexander recommended that the Commission reject PSO's request to increase the base rate allowance to $11.2 million, reducing PSO's requested revenue requirement by $8,263,753. He provided three reasons for rejecting PSO's request.

First, he noted that the seven years of historical data used to calculate the average overstate PSO's future storm damage recovery expenses because the Company's investments in improved distribution and transmission assets will reduce outage costs, particularly the investment in Advanced Metering Infrastructure ("AMI"). Mr. Alexander explained that AMI will allow PSO to locate and identify the extent of outages much more rapidly, avoiding costly restoration activities such as having personnel sweep storm-affected areas. He also noted that PSO's vegetation management activities will continue to reduce recovery expenses in the coming years by reducing the severity of outages.

Second, Mr. Alexander testified that deferring recovery of the full costs of storm damages creates the appropriate mix of incentives for the Company to quickly restore service at a reasonable cost after a major storm since PSO would not recover costs until after review. He stated that, by increasing the base rate allowance, risk would be effectively transferred to customers, who do not control recovery costs after major storms.

Third, Mr. Alexander testified that PSO's request should be evaluated in light of its overall position in the rate case. He noted that PSO is requesting a large increase in rates, which already includes an annual cost of $9.8 million to amortize prior years' storm damage recovery expenses. Mr. Alexander explained that both increasing the base rate allowance based on prior years' data and also amortizing prior years' expenses would unnecessarily exacerbate the burden of PSO's requested rate increase and should be rejected.

WILLIAM W. DUNKEL

Mr. William W. Dunkel pre-filed responsive testimony on behalf of the Attorney General of the State of Oklahoma. He testified to his educational and professional background as a consulting engineer specializing in utility and regulatory proceedings. He has testified previously before the Oklahoma Corporation Commission and his qualifications as an expert have been accepted.

Nationwide, Mr. Dunkel's firm frequently participates on behalf of Commissions, Commission staffs, and Administrative Law Judges. As an expert on depreciation, Mr. Dunkel proposes depreciation rates that are fair to all parties, including investors, current ratepayers and future ratepayers.

In this case, the depreciation rates proposed by Public Service Company of Oklahoma ("PSO") would increase the annual depreciation expense by more than $40 million. Mr. Dunkel found that the evidence supports revised depreciation rates that would result in an annual depreciation expense at approximately half the level requested by PSO, or $ 22.3 million.

1. The PSO "Conceptual" Demolition Cost Estimates

PSO proposes to greatly increase the "conceptual" demolition cost estimates of the PSO production plants. The firm that prepared the PSO "conceptual" demolition cost estimates, Sargent & Lundy, has never actually demolished a production plant, as is done at the end of a production plant's life. The only American Electric Power Service Company production plant for which Sargent & Lundy prepared a "conceptual" demolition cost estimate that was later actually demolished is the Breed Plant in Indiana. Sargent & Lundy's "conceptual" demolition cost estimate was $28.7 million for the Breed Plant, but it subsequently only cost $10.8 million to actually demolish it. Sargent & Lundy's "conceptual" demolition cost estimate was 2.5 times the subsequent actual demolition cost of that same production plant.

In PSO's 2015 rate case, Cause No. PUD 201500208, the Commission properly rejected some of the costs PSO had included in its "conceptual" demolition cost estimates, including rejecting "contingency costs" and rejecting "escalation." In this proceeding, Mr. Dunkel has made these and other appropriate corrections to PSO's proposed "conceptual" demolition cost estimates.

For example, PSO included in its claimed "conceptual" demolition cost estimates a "contingency cost." In this "contingency cost," PSO assumed that (1) scrap values would be 15% less than PSO otherwise determined, and (2) the labor costs would be 15% higher than PSO had otherwise determined, and the material costs would be 15% higher than PSO had otherwise determined, and the indirect costs would be 15% higher than PSO had otherwise determined.

In fact, these values could vary in either direction. PSO's assumption that all of these amounts would vary in the direction that would increase the cost to the ratepayers is a onesided assumption. Mr. Dunkel did not include any contingency adjustment in his calculations. The Commission properly rejected the contingency cost that PSO proposed in PSO's 2015 rate case, and the Commission should reject that proposal in this case as well.

PSO witness Spanos greatly increased the claimed number of dollars needed to demolition a plant by restating the number of dollars in lower-value future dollars. For example, for the Riverside Plant, Mr. Spanos started with the Sargent & Lundy's "conceptual" demolition cost estimate of $31.3 million, which is in year-2017 dollars. However, Mr. Spanos estimated that because of future inflation, dollars in the year 2056, when this plant is expected to retire, will be worth only $0.38, if the current dollar is considered worth $1.00. So, Mr. Spanos increased the "conceptual" demolition cost estimate to be the number of dollars worth $0.38 that he estimates would be needed, which is $82.1 million in future dollars worth $0.38. Of course, current ratepayers will be paying in current dollars worth $1.00. Therefore, there is a large mismatch between the currency used to determine the claimed demolition cost and the currency which would be collected from ratepayers. The Commission properly rejected "escalation" in PSO's 2015 rate case, and it should do so again in this proceeding.

Mr. Dunkel addressed other issues in the PSO "conceptual" demolition cost estimates, including: (1) PSO used a different data source for the value of scrap than the source that had been used in PSO's 2015 rate case; (2) PSO used a different source for the contractor's labor rates than the source that it had used in PSO's 2015 rate case; and (3) PSO changed how the estimated contractor's general and administrative costs and estimated contractor's profit are included in the "conceptual" demolition cost estimate. In the last PSO case, Cause No. PUD 201500208, the Commission adopted a $15.2 million estimated demolition cost for the Riverside Plant, in year 2015 dollars. In this proceeding Mr. Dunkel recommends a $19.9 million estimated demolition cost for the Riverside Plant, in year-2017 dollars. Mr. Dunkel likewise addressed the estimated demolition cost for all of the production plants.

2. Average Service Lives

Among the accounts other than production plant accounts, by far the largest depreciation expense increase that PSO proposes is for Account 367, Underground Conductors and Devices. Two years ago in PSO's 2015 rate case, the PSO depreciation expert witness Mr. Spanos recommended a 65-year Average Service Life (ASL) for this account. However, in the current case, Mr. Spanos now recommends a 45-year ASL for this same account. A 45-year ASL causes a $4 million per year increase in the depreciation expense, as compared to a 65-year ASL. It turns out that during the last two years, PSO has altered the data from the past that is considered when establishing a service life recommendation. It is this altered, so-called "historic data" that supports the 45-year ASL that PSO now proposes. In response, Mr. Dunkel presented the appropriate lives for this and certain other accounts.

3. Net Salvage

Regarding net salvage, the National Association of Regulatory Utility Commissioners' Public Utility Depreciation Practices states:

"Normally, the process should start by analyzing past salvage and cost of removal data and by using the results of this analysis to project future gross salvage and cost of removal."

For Account 367, Underground Conductors and Devices, the net salvage amount PSO actually incurred averaged $600,228 per year in recent years. However the net salvage annual accrual for this account that PSO witness Spanos proposes is $2,046,374. The annual accrual amount is an expense to be recovered from ratepayers in this rate case proceeding. For Account 367, the annual accrual that Mr. Spanos is proposing for net salvage is over three times the annual amount PSO actually incurs for net salvage. Mr. Dunkel proposes net salvage factors that have a more reasonable relationship between the annual amounts that would be charged to ratepayers for net salvage, compared to the annual amounts that PSO actually incurs for net salvage.

4. Incorrect Information

Mr. Dunkel discovered that PSO witness Spanos had incorrectly used 2.92% as the currently approved rate for "amortized" investments in Communications Equipment Account 397.00, and Mr. Dunkel determined the correct approved rate is 6.67%. In response to discovery, Mr. Spanos acknowledged that in PSO's 2015 rate case, the Commission had adopted PUD witness David Garrett's recommendation on this issue, but Mr. Spanos denied that 6.67% is the correct approved rate for the "amortized" investments in Account 397.00. The documents filed by PUD in PSO's 2015 rate case clearly show that the PUD witness David Garrett recommended 6.67% for the "amortized" investments in Communications Equipment Account 397.00 (as is shown on Attachment WWD-19 to Mr. Dunkel's testimony).

5. Conclusion

The annual accruals produced by the depreciation rates Mr. Spanos recommends, and the depreciation rates the Attorney General recommends, compared to the current depreciation rates, are shown in the following table.

Comparison of Annual Accruals based on 12/31/2016 Investments

Functional Category	12/31/16 Investment	Current Approved Accrual Amount	PSO Proposed Accrual Amount	PSO Difference from Current	AG Proposed Accrual Amount	AG Difference from Current	AG Difference from PSO
Steam Production	1,347,167,098	28,767,126	49,674,822	20,907,696	43,694,020	14,926,894	(5,980,802)
Other Production	157,116,666	3,810,749	6,080,057	2,269,308	5,137,363	1,326,614	(942,694)
Transmission Plant	829,627,759	17,915,352	20,950,776	3,035,424	20,577,349	2,661,997	(373,427)
Distribution Plant	2,314,365,056	63,672,248	76,238,432	12,566,184	65,999,451	2,327,203	(10,238,981)
General Plant	145,659,037	4,196,769	5,143,499	946,730	4,892,066	695,297	(251,433)
Unrecovered Reserve Amort.			313,063	313,063	313,063	313,063	0
Total	4,793,935,617	118,362,244	158,400,649	40,038,405	140,613,312	22,251,068	(17,787,336)

For the reasons discussed in the responsive testimony filed by Mr. Dunkel on September 21, 2017 on behalf of the Attorney General, the depreciation rates and parameters shown in the "AG Proposed columns" on Attachment WWD-21, attached hereto for convenience, should be adopted.

TODD T. BOHRMANN

Mr. Todd F. Bohrmann pre-filed responsive testimony on behalf of the Attorney General of the State of Oklahoma. He testified as to his educational and professional background. He has not testified previously before the Oklahoma Corporation Commission, but has testified on three occasions before the Florida Public Service Commission. Mr. Bohrmann recommended a specific adjustment to rate base associated with Public Service Company of Oklahoma's ("PSO") retired Northeastern Unit 4.

To incent PSO to maximize its use of Northeastern Unit 4, Mr. Bohrmann proposed that the Commission include in PSO's rate base only the following components: 1) structures and equipment, recorded at net book value, that Northeastern Unit 4 shares in common with Northeastern Unit 3, while Northeastern Unit 3 remains in commercial service; and 2) materials and equipment, recorded at net book value, salvaged from Northeastern Unit 4 for use at a PSO generating unit. To the extent that PSO can utilize materials and equipment from Northeastern Unit 4 elsewhere, the value thereof can be included in the Company's rate base. Any remaining part of Northeastern Unit 4 should be excluded from the Company's rate base.

Mr. Bohrmann's testimony summarizes the actions that PSO undertook to comply with the federal Clean Air Act, as well as a related settlement between PSO, the U.S. Environmental Protection Agency, the U.S Department of Justice, Secretary of Energy and Environment for the State of Oklahoma, the Oklahoma Department of Environmental Quality, and the Sierra Club ("EPA Settlement"). Mr. Bohrmann's testimony details the Commission's decisions regarding PSO's environmental compliance plan in PSO's 2015 rate case, Cause No. PUD 201500208. In that case, the Commission ordered the following: 1) base rate recovery to plant investment attributable to PSO's environmental compliance plan in service no later than July 31, 2015; 2) deferred recovery until PSO's next rate case for plant investments related to PSO's environmental compliance plan that were not in service by July 31, 2015, which includes Northeastern Unit 3 and Comanche Power Station; 3) no change in the depreciation schedule for Northeastern Units 3 and 4; and 4) deferred consideration until PSO's next rate case on whether PSO should be provided an opportunity to earn a return on the undepreciated book value of Northeastern Unit 4.

Mr. Bohrmann's testimony makes the distinction between the "used and useful" concept and the prudence standard as it relates to cost recovery of PSO's investments from ratepayers. The prudence standard gauges whether a utility's decisions were reasonable at the time these decisions were made, given what the utility knew or should have known. The concept of "used and useful" is a fundamental longstanding ratemaking concept in which a utility's opportunity to earn a return is limited to only those assets that are "used" (i.e., not under construction or standing idle awaiting abandonment) and "useful" (i.e., actively helping the utility provide efficient service) In this case specifically, Mr. Bohrmann disagrees with PSO's argument that the Commission's prior rulings on the "used and useful" status of Northeastern Unit 4 is relevant for setting rates in the instant proceeding.

Mr. Bohrmann's testimony posits that PSO's currently retired Northeastern Unit 4 is no longer "used and useful" because this unit is: 1) duplicative of other PSO power resources used to serve native load; 2) not economically competitive; and 3) technologically obsolete. Mr. Bohrmann's testimony indicates that PSO has informed the financial community about Northeastern Unit 4's unresolved status, pending a Commission decision in the instant proceeding. PSO has also informed the financial community about the potential negative impact on future net income and cash flow if PSO is not allowed to earn a return on the undepreciated book value of Northeastern Unit 4. Mr. Bohrmann's testimony indicates that these types of adjustments to future net income and cash flow have occurred industry-wide in recent years with the U.S. electric utility industry, including PSO's parent company, reducing the value of the assets on the industry's collective balance sheets by $55 billion between 2012 and 2016.

Mr. Bohrmann's testimony asserts that the current value of Northeastern Unit 4 is less than when the unit was in commercial operation. The question that the Commission must answer is "Who pays for the reduction in value – ratepayers or shareholders"? Mr. Bohrmann's proposal spreads this loss of value fairly between these two groups, while incenting PSO to maximize the remaining value left in Northeastern Unit 4. Second, this proposal sends the appropriate signal to PSO and other regulated utilities in Oklahoma that utility management should always seek out creative solutions to maximize value for its ratepayers.

Department of Defense

MAUREEN L. RENO

The United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") filed the Responsive Testimony of Maureen L. Reno on September 21, 2017 in Cause No. PUD 201700151. Ms. Reno, who is employed as an independent consultant, has 16 years of regulated utility and energy sector experience. She has earned undergraduate and graduate degrees in economics. The purpose of her testimony is to recommend, for ratemaking purposes in this case, an overall rate of return, a capital structure, and a fair rate of return on equity ("ROE") for Public Service Company of Oklahoma ("PSO" or "Company") under Cause No. PUD 201700151. Ms. Reno testifies, among other things, on the following issues:

- Assessment of the Company's proposed Capital Structure and Overall Rate of Return, with recommendations on the allowed rate of return on rate base;
- The current economic and financial conditions that affect investors' opportunity cost of capital, both in general and for utility companies;
- Development of an alternative proxy group based on the proxy group and sample criteria presented by the Company's cost of capital witness, Mr. Michael J. Vilbert, to calculate an estimate of the Company's cost of equity; and

- Analysis of cost of equity based on variations of the Discounted Cash Flow ("DCF") method, reasonable growth rates, and the Capital Asset Pricing Model ("CAPM").

Capital Structure and Overall Rate of Return

Ms. Reno accepts PSO's proposed cost of long-term debt of 4.60 percent. Ms. Reno also accepts the Company's proposed capital structure of 48.51 percent equity and 51.49 percent long-term debt, but she disagrees with the Company's cost of common equity of 10.0 percent. Ms. Reno testifies that Mr. Vilbert's recommended cost of equity is overstated due to his use of inputs with an upward bias, particularly his reliance on high earnings growth rates and quarterly dividend yields that are based on only two weeks of stock market valuations and improper use of Commission-authorized returns when calculating his equity risk premium. Ms. Reno's cost of capital recommendations can be summarized as follows:

Capital Item	Percent	Pre-Tax Cost	Return
Long-term Debt	51.49%	4.60%	2.73%
Common Equity	48.51%	8.00%	3.88%
Total Cost of Capital:	**100.00%**		**6.25%**

Ms. Reno recommends an overall allowed rate of return of 6.25 percent, based on an ROE of 8.0 percent, an embedded cost of long-term debt of 4.60 percent, and a capital structure comprised of approximately 51.5 percent long-term debt and 48.5 percent equity.

ROE Analysis

In determining her recommended return, Ms. Reno studies the current, near-term, and forecasted financial markets. She also examines national and regional economic trends to assess investors' opportunity cost of investing in a share of utility, also known as the cost of equity capital. Despite a resurgence in economic growth, the Federal Reserve continues to maintain near record-low short-term interest rates. This delayed action and low long-term inflation expectations have driven down long-term bond rates and expected market returns on equity investment.

Ms. Reno's cost of equity analysis employs Mr. Vilbert's proxy group, minus the following companies: American Electric Power Company; AVANGRID, Inc.; CenterPoint Energy; Entergy Corporation; Eversource Energy; SCANA Corporation; and Sempra Energy. This alternative proxy group removes a series of questionable firms that violate Mr. Vilbert's own sample criteria. Consistent with Mr. Vilbert's criteria, Mr. Reno excludes firms that are currently or have recently been involved in any significant merger and acquisition activities as well as companies that are experiencing financial distress. Ms. Reno also excluded the Company's parent because it introduced circularity into Mr. Vilbert's analysis.

Ms. Reno uses variants of the Single-Stage and Three-Stage DCF models to form the basis of her recommendation of 8.0 percent ROE for PSO, which is the midpoint of her range of 7.4 percent to 8.6 percent. Her CAPM results show a wider range of 6.75 percent to 8.84 percent.

The first cost of equity model Ms. Reno employs is the DCF, which has two components—the dividend yield and the expected growth rate. She calculates the dividend yield for each company in her sample by dividing the current annualized dividend rate by the average stock price for both 90 days and 180 days ended September 8, 2017. She then adds the dividend yield to each company's growth rate. In addition to employing expected earnings growth for the growth rate (as Mr. Vilbert does), Ms. Reno uses expected dividend growth, expected book value growth, and sustainable growth rates because investors consider a wider array of information to assess risk in addition to earnings growth (instead of only expected earnings growth). Ms. Reno's range of Single-Stage DCF results are 7.50 percent to 8.38 percent.

Ms. Reno's Three-Stage DCF model is an enhancement of the Single-Stage DCF model, which allows dividends, earnings, and book value to grow at different rates over time. Ms. Reno finds a growth rate of 4.3 percent, which is based on expected growth in nominal gross domestic product. She also employs a final stage growth rate of 5.5 percent as a sensitivity. The range of Three-Stage DCF results are 7.42 percent to 8.57 percent.

Ms. Reno's third cost of equity model is the CAPM, which includes three components—the risk-free rate, the beta, and the risk premium. For the risk-free rate, Ms. Reno uses two estimates: the first is the one-month average of the yield on 30-year U.S. Treasury bonds for the period ended September 8, 2017, and the second is the one-month average yield on 20-year U.S. treasury bonds over the same period. Ms. Reno multiplies Value Line betas for each proxy group company by her equity risk premium. To estimate the equity risk premium, she measures the return differentials between common stocks and the risk-free rate. Her CAPM results using the 30-year U.S. Treasury bonds are 7.00 percent and 8.84 percent. Her CAPM result using the average yield on the 20-year U.S. Treasury bond is the minimum of her range at 6.75 percent.

Ms. Reno also uses the Comparable Earnings ("CE") Analysis to show that her recommended ROE is reasonable. She uses the CE method by examining realized ROEs for her proxy group and comparing investor acceptance of these returns via corresponding market-to-book ratios ("M/B"). She shows that the companies in her proxy group were successful in attracting investors given reported historical book value-derived ROEs. Even in cases where a company's ROEs were as low as 7.8 percent and 8.0 percent, a company's stock was valued higher than book value as demonstrated by M/B ratios greater than 1.

Ms. Reno places more importance on her DCF derived results because it is the predominant methodology used by both the finance community and public utility commissions (including the Oklahoma Corporation Commission) and yields more reliable results. The DCF is a forward-looking model that directly incorporates investors' expectations of company dividend income through market pricing signals. The CAPM model, in contrast, is largely reliant on financial market outcomes complicated by monetary policy and near historically low interest rates. These low interest rates have persisted many years longer than anticipated.

Conclusion

Ms. Reno recommends that the Commission authorize an overall rate of return of 6.25 percent, using the test-year and pro forma adjusted capital structure that incorporates a cost on long-term debt of 4.60 percent and an allowed ROE of 8.0 percent. Her recommendation lies within the range of 7.4 percent and 8.6 percent, and represents a conservative estimate of a fair and reasonable ROE for PSO. Ms. Reno's results are derived using a proxy group of electric utilities with similar overall risks as the Company, and best represents the opportunity cost of capital that an investor expects under today's financial and economic circumstances.

MAUREEN L. RENO – SUMMARY OF SUPPLEMENTAL

The United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") filed the Responsive Testimony of Maureen L. Reno on September 21, 2017 in Cause No. PUD 201700151. Ms. Reno filed Supplemental Testimony on October 5, 2017.

In its response to DOD/FEA Data Request 2-9, PSO witness Michael Vilbert stated that as of August 31, 2017, he would exclude Sempra Energy and Vectren Corp. from his sample of proxy companies, and he would include Duke Energy, NextEra Energy, and Unitil Corp.

In accordance with Mr. Vilbert's stated criteria, Ms. Reno had excluded Sempra Energy because it was recently involved in substantial merger and acquisition activities. However, Ms. Reno had included Vectren Corp. because she had been unaware of a news report dated August 22, 2017, indicating that, based on anonymous sources, Vectren was considering options including a potential sale. Based on this news report, Ms. Reno agreed with Mr. Vilbert that Vectren should be excluded from her sample of proxy companies. Ms. Reno also agreed with Mr. Vilbert that Duke Energy and NextEra Energy should be included because their mergers had been completed more than five years before. However, Ms. Reno disagreed with Mr. Vilbert regarding Unitil Corp. because there is incomplete data on the company to calculate consistent results across all her analyses.

Ms. Reno performed the same analyses set forth in her Responsive Testimony with the modified sample (excluding Vectren and including Duke Energy and NextEra Energy). Applying her analysis to the modified sample proxy group yielded only marginal changes to her prior ROE estimates. Her new range, based on her DCF model sensitivities, became 7.39 percent to 8.62 percent, with a midpoint of 8.01 percent. In comparison, her original estimate range was 7.33 percent to 8.57 percent, with a midpoint of 7.95 percent. Since both the original midpoint and new midpoint round to 8.0 percent, her original ROE recommendation of 8.0 does not change.

LARRY BLANK

On October 3, 2017, Dr. Larry Blank filed responsive testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") addressing the PSO class cost of service study, rate design, and PSO's proposal to include an ad valorem tax adjustment to the Tax Adjustment (TA) Rider. Dr. Blank testifies in support of the following:

- First, the class cost of service study filed by the Company should be modified to utilize the 4 CP methodology for the allocation of transmission-related costs. The 12 coincident peak demand ("12-CP") methodology used by PSO does not correspond to actual transmission load characteristics and is inconsistent with an accepted industry practice to only include monthly peak demands within 90% of the annual system peak demand. Based on actual PSO load data, the months of June, July, August, and September all fall within 95% of the system peak demand that occurred in August 2016 and none of the other months are close. October is the next closest month at 77.2%, as reflected in the following table.

Table 1. PSO Monthly Peak Demands

	Jan-16 Demand	Feb-16 Demand	Mar-16 Demand	Apr-16 Demand	May-16 Demand	Jun-16 Demand	Jul-16 Demand	Peak Aug-16 Demand	Sep-16 Demand	Oct-16 Demand	Nov-16 Demand	Dec-16 Demand
JURISDICTIONAL												
TOTAL RETAIL	2,558,825	2,332,430	2,178,288	2,551,469	2,945,463	3,881,684	3,909,814	3,989,010	3,792,391	3,080,681	2,675,910	2,773,124
TOTAL WHOLESALE	1,382	1,212	1,233	1,146	1,369	2,228	2,268	2,366	2,012	1,336	1,161	1,222
TOTAL	2,560,206	2,333,642	2,179,520	2,552,615	2,946,832	3,883,913	3,912,082	3,991,377	3,794,403	3,082,016	2,676,672	2,774,346
Percent of August System Peak	64.1%	58.5%	54.6%	64.0%	73.8%	97.3%	98.0%	100.0%	95.1%	77.2%	67.1%	69.5%

- Second, Dr. Blank supports the PSO proposal to move its major retail rate classes to its required cost-to-serve based on the cost of service study rather than a revenue distribution that deviates from cost of service.
- Third, Dr. Blank recommends that the Commission approve PSO's rate design proposals—specifically, the proportionate increase in all rate elements of a particular rate schedule or rate class.
- Fourth, Dr. Blank recommends rejection of the ad valorem tax adjustment proposed by PSO. This as an extreme example of single-issue, or piecemeal, ratemaking in that it would allow for a single source of plant-related cost increase without considering possible offsetting cost decreases due to more efficient modern plant. He recommends that the Commission deny the proposed ad valorem tax adjustment as unwarranted single-issue ratemaking.

Wal-Mart Stores East, LP, And Sam's East, Inc.

Steve W. Chriss

Steve W. Chriss filed responsive cost of service and rate design on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., (collectively "Walmart"). Mr. Chriss is Director, Energy and Strategy Analysis, with Wal-Mart Stores, Inc.

Walmart operates 136 retail units and employs 33,335 associates in Oklahoma. In the fiscal year ending 2017, Walmart purchased $775.5 million worth of goods and services from Oklahoma-based suppliers, supporting 22,604 supplier jobs. Walmart has 49 stores, a distribution center and additional related facilities that take electric service from Public Service Company of Oklahoma ("PSO" or "the Company") primarily on the Large Power and Light Primary Service schedule.

Mr. Chriss' recommendations are as follows:

1) Walmart does not take a position on the Company's proposed cost of service study at this time. Walmart will address proposed alternative cost of service models or modifications to the Company's model, if any, in accord with the Commission's procedures in this docket.

2) Walmart does not oppose the Company's proposed revenue allocation methodology.

3) If the Commission determines that the appropriate level of revenue requirement is lower than the level proposed by the Company, the Commission should follow the Company's proposed revenue allocation methodology and move the revenue requirements for each major customer class to its respective cost of service-based level.

RATE DESIGN TESTIMONY

Oklahoma Industrial Energy Consumers

SCOTT NORWOOD

Mr. Scott Norwood is an energy consultant and President of Norwood Energy Consulting, L.L.C. He testified on behalf of OIEC. His business address is P.O. Box 30197, Austin, Texas 78755. OIEC's members are among the largest users of electricity on PSO system, and therefore are very sensitive to any electric rate increases or ratemaking proposals by PSO that are unjustified or that otherwise effect amounts charged for energy usage.

Mr. Norwood is an electrical engineer with over 35 years of experience in the electric utility industry in the areas of power plant operations, electric resource planning and procurement, and regulatory consulting. He has filed testimony in over 200 electric utility regulatory proceedings including numerous past proceedings before the Commission over the last 20 years. He has also filed testimony in regulatory cases involving electric restructuring, base rate, fuel recovery, power plant certification and demand-side management matters, before state regulatory commissions in Alaska, Arkansas, Florida, Georgia, Illinois, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, Ohio, Oklahoma, Virginia, Washington, and Wisconsin. He has testified on behalf of OIEC in a number of past PSO regulatory proceedings, including base rate cases, fuel prudence cases, and proceedings involving the Company's environmental compliance plan and generating resource investments. Through this past work, he is familiar with PSO's system operations, generating resources and ratemaking practices. He has represented OIEC in regulatory proceedings before the Commission) for nearly 20 years. His resume and a listing of his past testimony are attached as Exhibit SN-1 to his responsive testimony filed in this Cause.

The purpose of Mr. Norwood's testimony is to present his findings and recommendations regarding various deficiencies which exist in PSO's current Fuel Cost Adjustment ("FA") Rider and SPPTC tariff. His findings and recommendations regarding these two issues are explained further below.

PSO's Fuel Adjustment Clause Rider

With regard to the FA Rider, which establishes the monthly Fuel Cost Adjustment ("FCA") charges to customers, PSO's existing tariff does not provide for adequate review of monthly FCA charges or proposed changes to the FA Rider and allows the Company inordinate latitude regarding the timing and level of FCA revisions. Moreover, in many cases, customers are provided virtually no opportunity for advanced review of the reasonableness or need for FA Rider revisions before such revisions are placed into effect. This almost total lack of transparency and oversight in the rate setting process for the FA Rider is particularly problematic for industrial and large commercial customers who use large volumes of energy.

Mr. Norwood has five primary recommendations to improve PSO's FA Rider. First, he recommended that PSO be required to file an application with the Commission to revise the FCA on a regular schedule once each year. He recommended that such applications be filed 60 days prior to the first billing cycle in October, when the proposed FCA rates would be scheduled to into effect. He further recommended that PSO's FCA filing package include testimony and schedules that present the FCA calculation, the underlying forecast of costs supporting the FCA, a discussion of the primary factors that are causing the need for the FCA revision, and estimated impacts of the proposed FCA revision on customers for each rate class. Mr. Norwood further recommended that PSO be required to supply a complete electronic copy of the FCA application and filing package to each party in the Company's most recent base rate proceeding at the same time it makes the filing with the Commission.

The scope of these annual FA Rider revision proceedings would be limited to the reasonableness of the annual FCA calculation and PSO's forecast underlying the proposed revisions, with issues regarding the prudence of expenses recovered through the FCA and the final reconciliation of fuel cost over- and under-recoveries for each rate class reserved for PSO's annual fuel proceedings. He further recommended that PSO be required to provide electronic copies of its existing monthly fuel reports to OIEC and other parties that have participated in the Company's most recent base rate proceeding at the same time such reports are provided to PUD Staff so that customers can track the trends in PSO's fuel expenses and FCA over- and under-recovery balances.

His second recommendation is that the FA Rider should be revised to eliminate the current provision for interim adjustments. The existing provision provides PSO with wide latitude to adjust its fuel charges "whenever the annual cost of fuel begins to vary significantly from the cost used in the annual fuel cost adjustment factor or the over/under-recovered balance is $50,000,000 or more." There are simply too many situations in which the above standard could arguably apply without a significant need for adjusting the FAC.

Moreover, it is not necessary for PSO to make interim adjustments since the FAC factor formula already provides for ongoing adjustments to address fuel over- and under-recoveries, and therefore has a self- correcting mechanism that will tend to offset sustained over- or under-recoveries. Mr. Norwood believes that eliminating the interim adjustment provision will provide customers with greater certainty of the timing and level of changes to PSO's fuel charges and will simplify regulatory oversight and monitoring of PSO's FCA charges.

His third recommendation is that the DEFS term of the FCA formula should be modified to shorten the period over which accumulated fuel over-recovery balances are refunded to customers from 12 months to 1 month. This proposed revision will help minimize over-recovery impacts on customers and reduce any incentive for the Company to overstate fuel costs. By more quickly refunding fuel over-recoveries, this revision should further reduce the need for interim adjustments.

Mr. Norwood's fourth recommendation is that the FA Rider should be revised to require PSO to provide electronic copies of the FCA reports that it provides each month to PUD staff, to each party in the Company's most recent base rate proceeding.

Finally, he recommended that the OSEC term of the FCA formula be modified to explicitly exclude net revenues earned from SPP energy sales from the margin sharing provision that currently applies to off-system sales. The net revenues earned from sales into the SPP energy market are fundamentally different from margins earned on bilateral off-system energy sales that were made by PSO before the SPP Integrated Market was implemented. PSO is one of many participants in the SPP market and it supplies virtually all of its energy to the market and purchases all of its energy from the market. Under this new construct, decisions regarding when PSO's generating units will be dispatched are made by SPP and PSO needs no financial incentive to continue its participation in the SPP market.

PSO's Southwest Power Pool Transmission Cost Tariff

With regard to PSO's SPPTC tariff, it appears that PSO has virtually ignored existing tariff provisions that were originally intended to require the Company to justify the costs and benefits of such charges, and to address the reasonableness of third party charges collected through the SPPTC tariff, which totaled approximately $43 million in the test year. To address this problem, Mr. Norwood has three primary recommendations which are intended to improve the performance of PSO's existing SPPTC Tariff. First, he recommended that annual revisions to the SPPTC Tariff be made subject to review and approval by the Commission. In this regard, he recommended that PSO shall file an application with the Commission to revise the SPPTC Rider each year, 60 days prior to the first billing cycle in October, when the proposed rates are expected to be placed in effect. This filing would be made in the same proceeding that he recommended to address annual changes to PSO's FA Rider. The Company would be required to provide a filing package that includes testimony and schedules that support the SPPTC calculation, the underlying costs supporting the revision, a discussion of the primary factors that are causing the need for the revision, and estimated impacts of the proposed SPPTC revision on customers for each rate class. He recommended that PSO be required to provide a complete electronic copy of the SPPTC revision application and rate filing package to each party in the Company's most recent base rate proceeding, concurrent with the Commission filing. The scope of this SPPTC revision proceeding would be limited to the reasonableness of the SPPTC calculation. Issues regarding prudence of the underlying SPPTC charges and the final reconciliation of any over- or under- recovery of SPPTC expenses will be reserved for the Company's next annual base rate proceeding. He further recommended that any party may request a hearing on the proposed SPPTC revision by filing an objection with the Commission within 15 days of the filing of the joint FCA/SPPTC petition.

Mr. Norwood's second recommendation is to make explicit that the Company has an ongoing obligation to provide testimony which addresses the reasonableness of third party charges recovered through the SPPTC in future base rate proceedings. In this regard, he recommended that in each base rate case, the Company must provide testimony to support the reasonableness of expenses recovered through the SPPTC that have not been previously reviewed and approved by the Commission, as well as the reasonableness of any over- or under-recovery of such expenses.

Mr. Norwood's final recommendation that the current provision for the Company to implement interim adjustments to the SPPTC tariff at any time when an over-recovery of under-recovery of expenses exceeds 10% should be eliminated, since the SPPTC tariff already provides for addressing over- and under-recoveries of SPPTC costs in a future base rate proceeding.

MARK E. GARRETT

Witness Identification, Purpose of Testimony and Importance of the Case

Mr. Garrett's testimony addresses various revenue requirement issues and presents OIEC's recommended revenue requirement in this case. A summary of the OIEC impacts is shown below:

Rate Increase Proposed by PSO	$ 169,667,526
OIEC Adjustments	$ (117,336,487)
Riders rolled into Base Rates	$ (24,000,000)
Rate Increase after OIEC Adjustments	**$ 28,331,039)**

In its Application, PSO seeks a $169 million rate increase, which represents a 28.33% increase in base rates. This is one of the largest rate increases ever sought in the state of Oklahoma. In December of last year, the Commission established new rates for PSO. This case was filed on the heels of the Company's last rate case, Cause PUD 201500208. In fact, this case was pancaked on top of the last case, half way through the first year of the new rates from that case.

It appears that the Company is trying to relitigate many of the issues it lost in the last rate case. These issues include depreciation expense, payroll costs, incentive compensation and other O&M expense levels. The Commission set the appropriate level for these costs, and implemented them in January of this year. Yet, the utility is seeking to change these cost levels a short 6 months later. This is inappropriate. In reality, the purpose of this case was supposed to be to (i) recover capital investments associated with the remaining costs of PSO's Environmental Compliance Plan ("ECP") for assets that were not completed and in service in the Company's last rate case and (ii) recover capital investments associated with the Company's implementation of automated meters (AMI). It was not meant to be an opportunity for the Company to relitigate losses in the last case.

Rate Base – 6Month Post-Test Year Adjustments

Mr. Garrett propose adjustments to update the Company's rate base accounts to their balances at June 30, 2017. In Oklahoma, the Commission is required by law (Title 17 § 284) to give effect to known and measurable changes that occur within six months of test year end. In this application, the 6 month cut-off period for post test year adjustments is June 30, 2017. In virtually every litigated rate case since Cause No. PUD 200400610, ONG's 2005 rate case, which was the first rate case heard by the Commission after passage of the 6-month rule in Title 17 § 284, the Commission has used this approach. OIEC's adjustments to the Company's pro forma rate base are set forth in Mr. Garrett's responsive testimony.

Prepaid Pension Asset

Mr. Garrett proposes to reduce PSO's prepaid pension balance by $36,508,316, which represents the unexplained, and unsupported, starting balance from 2003 in the Company's prepaid pension calculations. The Company cannot account for what they claim is an existing starting balance. Without any support for this balance, it cannot be included in rates. The Company indicated that the supporting information was unavailable. In the Company's 2003 rate case, the utility used a test year of June 30, 2003 with a 6-month post-test year update period that ran through December 31, 2003. No prepaid pension asset was presented in that case. If there had been a prepaid pension asset in 2003, the time to include it in rate base would have been in that rate case. The revenue requirement impacts of this adjustment is $(3,766,782).

Disallowed Incentives in Rate Base

Each year, PSO capitalizes a portion of its incentive plan payments. These capitalized incentives are included in rate base where they earn a return. The Commission has consistently excluded 50% of PSO's short-term and 100% of the Company's long-term incentives from operating expense. In order to consistently apply the Commission's treatment of incentive compensation, the same portion of PSO's incentive payments excluded from operating expense for ratemaking purposes must also be excluded from rate base. If not, the Company will earn a return on, and eventually recover from ratepayers, compensation associated with incentive plans the Commission has disallowed. At test year end, $37,645,259 was included in rate base for incentives costs that should be removed. This adjustment is necessary to make the Commission's treatment of incentive costs in rate base consistent with its treatment of PSO's incentive costs in operating expense in PSO's prior litigated cases, including PUD 200600285 and PUD 200800144 and PUD 201500208. The revenue requirement impact of this adjustment is $(3,884,087)

Annual Incentive Compensation Expense

PSO seeks to include $9.098 million in rates for annual, short-term incentive expense, based upon the Company's targeted payout for incentive expense, according to the Company. Mr. Garrett proposes to exclude annual incentive expense related to financial performance measures. As a result, Mr. Garrett proposes to reduce the Company's requested level of annual incentive compensation by 75%, or $6,824,159.

PSO's 2016 Annual Compensation Plan is heavily dependent on financial performance measures. As in prior years, PSO's incentive plans are based upon various financial and operational measures, however, the overall funding available to pay annual incentive compensation is based 75% on AEP's earnings per share (EPS), as it was in PSO's last rate case, PUD 201500208. Under the Company's funding mechanism, regardless of how well individual employees may perform in nonfinancial performance areas such as customer satisfaction and safety, if the Company's EPS is low, payments to employees will be reduced accordingly, even to 0% if needed. Thus, under the Company's incentive compensation plan, corporate earnings is the primary driver in determining whether, and to what extent, incentive compensation will be paid each year. In fact, the Company's 2016 Overview states, "Linking annual incentive compensation to AEP's earnings aligns it with the value created for AEP's shareholders and ensures that AEP meets its shareholder commitments before setting aside dollars for employee rewards."

The 2016 Plan also makes the following statements regarding the 75% Funding Mechanism:

- Further <u>aligns the financial interests of all AEP employees with those of AEP's shareholders</u>;
- <u>Ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before employees are rewarded with annual incentive compensation</u>;

In prior cases, the Commission has consistently reduced the requested levels of incentive compensation based upon the fact that the plans are tied to the Company's financial performance. In PSO's last three litigated rate cases, the Commission reduced PSO's requested annual incentive compensation by 50% based upon the testimony and evidence in those proceedings that the plans were tied to financial performance.

Similarly, in OG&E's last two litigated rate cases, the Commission reduced OG&E's annual incentive plan costs for amounts tied to financial performance. In OG&E's last rate case, PUD 201500151, the requested amounts were reduced by 50% and in OG&E's 2005 rate case, PUD 200500151, the requested amounts were reduced by 60%.

As a general rule, regulatory commissions exclude incentive compensation associated with financial performance. When the costs associated with these plans are excluded, the rationale is generally based on one or more of the following reasons:

1) Payment is uncertain;
2) Many of the factors that impact earnings are outside the control of most company employees;
3) Earnings-based incentive plans can discourage conservation;
4) The utility assumes no risk associated with incentive payments;
5) Financial incentives should be paid out of increased earnings;
6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion.

Even though regulators routinely exclude financial-based incentive compensation payments based on one or more of the reasons outlined above, this does not mean that companies cannot offer financial-based incentives. However, when a financial-based incentive package is properly constructed, there will be ample additional earnings to fund these payments. Thus, ratepayers do not need to subsidize incentive plans designed to increase earnings.

Garrett Group LLC conducted an Incentive Compensation Survey of the 24 Western States in 2007, and updated it in 2015. The survey shows that the vast majority of the states surveyed follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. None of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule.

The argument that incentives should be included in rates because the amount is reasonable when compared with the amounts paid by other utilities misses the point. The question for regulators is not whether the amount paid for incentives is reasonable, but whether the incentives themselves are necessary for the provision of service. Further, when it comes to financial-based incentives, regulators ask who benefits more from these payments, ratepayers or shareholders.

Although utilities are free to offer whatever compensation package they want to offer, most commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings. Also, as stated above, because incentive pay related to financial performance is generally disallowed, most of the utilities that PSO competes with for talent generally do not recover all of their incentive compensation in rates. Therefore, PSO is not put at a competitive disadvantage when its incentive pay is similarly adjusted.

Long-term Stock Incentive Compensation Plan

The Company is proposing to recover $3,106,766 for its long-term incentive plan, which is the amount in pro forma operating expense after PSO's adjustment to increase test year expense to targeted levels for long-term incentives.

The long-term plan provides grants and awards in the form of performance units and restricted stock units (RSUs), both of which are generally similar in value to shares of AEP common stock. The performance units are granted based on two equally weighted performance measures: three-year total shareholder returns, and three-year cumulative EPS relative to a Board-approved target. As such, the Long-Term Incentive Plan is designed to align the interest of AEP's management with the interest of shareholders and to promote the financial success and growth of AEP.

Mr. Garrett testified that stock incentive compensation payments to officers, executives and key employees of a utility are generally excluded for ratemaking purposes. Officers of any corporation have a legal, fiduciary duty to put the interests of the corporation first. This means that these individuals are required to put the interests of the company above the interest of the customers. Since the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interest of the shareholders first.

The results of the Garrett Group Incentive Survey, discussed in the previous section of this testimony, show that most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that long-term, stock-based incentives are not allowed in virtually every state. In the synopsis of the incentive survey results from each state that was included in the prior section of this testimony, the treatment of long-term stock based incentives in each state is underlined. According to the survey, 20 of the 24 western states exclude all or virtually all long-term stock-based incentive pay. In the other four states, the issue has not come up. Mr. Garrett's proposed adjustment removes 100% of the cost of the plan in pro forma operating expense in the amount of $(3,106,766).

Supplemental Employee Retirement Plan ("SERP")

Mr. Garrett testified that the Company provides supplemental retirement benefits to officers, and division presidents of the Company. Supplemental retirement plans for highly compensated individuals are provided because benefits under the general pension plans are subject to certain limitations under the Internal Revenue Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $265,000 for 2015 and $270,000 for 2016. Retirement benefits on compensation levels in excess of annual compensation limits are paid through supplemental plans. Supplemental retirement plans for highly compensated employees are designed to provide benefits in addition to the benefits provided under the general pension plans of the company. The amount of SERP costs included in PSO's filed cost-of-service was $349,862, which is comprised of $96,780 for PSO and $253,082 for AEPSC. Mr. Garrett recommends excluding the SERP costs in this case as it has consistently done in the past.

Rate Case Expense

Mr. Garrett testified that PSO's requested rate case costs are significantly overstated. For example, an increase from $200,000 to $500,000 for outside legal fees appears excessive. In addition, $150,000 for a Return on Equity ("ROE") witness is far above market, which is between $25,000 and $50,000. Further, PSO's additional, and cumulative, ROE witness at $100,000 should be paid by shareholders. Also noteworthy, the Company seeks to include $107,000 for a demolition study that has been presented now in the Company's last three rate cases in Oklahoma. Finally, the Company seeks $43,500 for notice costs when those costs have been $5,000 in the past two rate cases. In Mr. Garrett's opinion, rate case expense costs should be scrutinized much more closely than they have been in the past. Moreover, the Commission should understand that not all rate case costs should be borne by ratepayers. Only the necessary costs to process a rate case should be borne by ratepayers and these necessary costs should be evaluated using a least-cost standard. Ratepayers should not be burdened with unreasonably inflated legal costs and expert witness fees, especially when the testimony appears to be self-serving shareholder testimony.

Mr. Garrett recommends that rate case expense be reduced from $1,161,066 to $590,566, and that rate case costs be recovered over a 4-year rather than a 2-year period. The longer recovery period will help lower rates now. A 4-year amortization of these costs results in an adjustment of $(432,892).

Storm Damage Expense

Since the Company is insulated from under-recovery through the tracker mechanism, there is no need to increase base rates now based on anticipated increases in storm damage expense in the future. In my opinion, the Commission should leave test year expense level where it is, and should continue to allow PSO to recover its excess storm expense through the approved tracker mechanism. This recommendation results in an adjustment of $(8,263,753)

Payroll Expense

Mr. Garrett testified that PSO annualized its test year costs and then added a 3.5% wage increase on top of that. Mr. Garrett testified that an annualization that multiplies a final pay period by 12 or 26 is only appropriate if the final pay period is representative of ongoing levels. Further, an additional increase for pay raises based on the nominal amount of the pay raises is not appropriate because payroll levels do not increase by the nominal amount of a pay raise. In other words, a 3.5% pay raise will almost never result in a 3.5% increase in payroll expense levels. Other factors can greatly impact payroll expense. These factors include: (1) the normal turnover; (2) workforce reorganizations; (3) productivity gains; and (4) capitalization ratio changes. All of these factors can impact overall payroll cost levels as much or more than pay raises do. For example, in PSO's last rate case, PSO requested a 3.85% increase in payroll costs from $53.096 million in the test year to $55.134 million, based again on post-test year pay raises. However, after that case, payroll costs actually went down by 1.01%, not up by 3.85% as the Company predicted.

PSO's new rates from the Company's last rate case went into effect in January 2017. This means that the reasonable level of payroll costs ordered by the Commission went into effect just eight months ago. Not even one year has passed since the Commission established this level. It is too early to set a new level for payroll costs. The Company's payroll adjustment methodology is unreliable, and not enough time has passes to tell whether or not the level established by the Commission in January of this year is sufficient.

Since the appropriate level for any operating expense is the test year level unless it can be shown that the test year level is not representative of the level that will be in effect during the rate-effective period, the amount that should be included in rates in this case is the test year level. Thus, Mr. Garrett's adjustments reverse the adjustments recommended by the Company for both PSO and AEPSC allocated costs, in the amounts of $(2,726,115) and $(2,773,667) respectfully.

Production Operating and Maintenance Expense

Mr. Garrett testified that PSO's proposed production O&M adjustments are unreasonable and would result in the Company collecting an excessive level of O&M expenses through its base rates. PSO's proposed adjustment of $293,664 to adjust test year expense for the retirement of Northeastern Unit 4 greatly understates the reduction in expenses that should reasonably result from retirement of the unit. It simply makes no sense that the cost to operate, maintain and staff one coal unit would only be 10% lower than the cost for two coal units, as PSO's adjustment suggests. Mr. Garrett recommends that PSO's test year O&M be reduced by $5.68 million for the Northeastern 4 retirement. This results in an allowed O&M level for Northeastern Unit 3 that is 68% of the level incurred for both Unit 3 and Unit 4, before Unit 4 was retired.

Also, PSO's proposed normalization adjustment (for the other power plants) is flawed in that it assumes that the three-year period used to determine "normal O&M levels" were in fact normal periods. The Company has not presented evidence to support this assumption. Moreover, during this period there were several major abnormal events that could have significantly impacted PSO maintenance expenses. For this reason, PSO's proposed $2.11 million increase to test year production O&M expense should be rejected.

Mr. Garrett adjustments reverse PSO's proposed production O&M adjustment in the amount of $(2,110,317), and reduce the test year O&M for Northeastern Unit 4 Production costs in the amount of $(5,680,000), for a total adjustment of $(7,790,317).

Southwest Power Pool (SPP) Transmission Expenses

PSO recovers SPP transmission expenses through base rates except for third party SPP Schedule 11 charges, which are recovered through the Company's SPPTC Tariff (excluding OK Transco). SPP expenses in base rate have more than doubled in the past four-year period, going from $22.5M in 2012 to $53.419M in the 2016 test year. PSO proposes adjustments primarily to annualize test year SPP charges. The net impact of these proposed adjustments increases SPP test year expense by another $17.64 million, or approximately 33%.

These adjustments are not supported by testimony or workpapers. PSO witness Hamlett indicates that the support for the increase is provided in his testimony and the testimony of PSO witness Ross. However, Mr. Hamlett provides only has one paragraph and a single workpaper page and Ross discusses the general nature of SPP expenses but does not address the specific test year adjustments to SPP expenses proposed by the Company in this case.

The third-party charges underlying the amounts billed from SPP that PSO seeks to recover in base rates include post-test year projected costs. PSO's proposed adjustments fail to meet the "reasonable and necessary" and "known and measurable" standards in Oklahoma, under (Title 17 O.S. § 284).

The SPP charges also include charges from the Company's affiliate, Oklahoma Transco. These affiliate charges include an 11.2% return on equity (ROE), which is significantly higher than the authorized return in Oklahoma. It is inappropriate for PSO to charge ratepayers through an affiliate a higher ROE than it is allowed to recover itself.

Mr. Garrett recommends that PSO's proposed test year adjustments be rejected. This recommendation results in a $16.06 million reduction to the level of SPP charges which PSO proposes to recover through its new base rates.

PSO's testimony in this case indicates that the Company collected approximately $42.88 million of SPP charges through its SPPTC Tariff during the test year. The SPPTC Tariff defines PSO's obligations to support charges recovered under this rider as follows:

> The company will address the reasonableness of SPP Expenses collected through the SPPTC during the next PSO base rate case and in future base rate cases.

Except for the brief mention of the SPPTC charges in Mr. Hamlett's testimony, no PSO witness addresses the reasonableness of specific charges collected through the SPPTC during the test year or in periods since the test year in the Company's last base rate case.

PSO has failed to adhere to the explicit requirement of the SPPTC Tariff with regards to demonstrating the reasonableness of past expenses collected through the SPPTC. For this reason, Mr. Garrett believes that the Commission could, in its discretion, order PSO to refund the $42.88 million of test year charges collected through the SPPTC.

Recovery of Northeastern Unit 4 Costs

PSO is proposing to retire the 460MW Northeastern Unit 4 coal plant in the middle of its useful life, but wants to include both a "return on" and a "return of" the plant costs in rates. The un-depreciated plant balance for Northeastern Units 4 at June 30, 2017 net of associated ADIT was $50.7 million. The annual rate base "return on" this amount would be $5.2 million and the annual depreciation expense is approximately $4.1 million, making the total annual cost to ratepayers about $9.3 million. PSO's proposal to include these costs in rates is inappropriate. Oklahoma law is very clear on this point: only assets "used and useful" for providing utility service may be included in rate base. Further, a plant's "used and useful" status is determined based upon the value of the property used and useful in public service at the time the inquiry was made, thus, in the test year plus six months. Unit 4 was taken out of service in April 2016. Since Unit 4 is no longer in service and is no longer used and useful, it should be removed from rates.

Mr. Garrett provided several relevant examples from Ohio, New Mexico, Texas and Oklahoma, where plants that were not used and useful were removed from rates. He also provided relevant precedent in Oklahoma from OG&E's 1991 rate case, PUD 91-1055.

OG&E had taken its Arbuckle generating plant out of service in response to load lost in the economic downturn that occurred at that time, but tried to include the costs of the retired plant in rate base under a theory that the plant could be returned to service when the economy recovered. The Commission, however, found that the plant was not used and useful because it was no longer in service, and could not be included in rate base. The Commission did allow OG&E the opportunity to return the plant to rate base if it was ever re-powered and returned to service. With the plant excluded from rate base the utility was not able to include the plant's depreciation expense in rates either. In effect, the Arbuckle plant became Plant Held for Future Use. As such, the return on and the return of the plant were both excluded from rates.

Mr. Garrett testified that Northeastern Unit 4 should be excluded from rates because the plant is no longer used and useful. This would leave open the possible return of the plant to rate base if the plant is eventually returned to service – either converted or repowered – in the future. The impact of this adjustment on the revenue requirement is $(9.37) million.

Attorney General

TODD F. BOHRMANN

Mr. Todd F. Bohrmann pre-filed responsive testimony on behalf of the Attorney General of the State of Oklahoma. He also filed responsive testimony on behalf of the Attorney General in this cause on September 21, 2017, on the revenue requirement requested by Public Service Company of Oklahoma ("PSO" or "Company"). Mr. Bohrmann has two recommendations regarding PSO's proposed rate design. First, the Oklahoma Corporation Commission ("Commission") should not approve PSO's request to make a pro forma adjustment of approximately $3.2 million for fuel procurement, unloading, and handling ("internal costs"). Through PSO's proposed adjustment, the Company is seeking to continue to recover these internal costs through the Fuel Adjustment Clause ("FAC" or "Fuel Clause"), instead of the more appropriate method of requesting those costs be added to base rates set in the current proceeding. Second, the Commission should not approve the Company's request for its proposed change to its Tax Adjustment Rider ("TA Rider"). The Company is requesting that the TA Rider be broadened to include changes to property (ad valorem) taxes paid by the Company, but this request does not meet the criteria necessary to be considered for a rider recovery mechanism. Property (ad valorem) taxes should instead remain included in base rates.

Mr. Bohrmann explained that several extraordinary factors occurred simultaneously during the 1970s that led state public utility commissions to adopt fuel adjustment clauses – a mechanism outside of base rates. Those factors, he explained, include the following: 1) sharp price increases for residual oil, coal, and natural gas; 2) changes in generation mix by fuel type were not sufficient to avoid the need for a fuel adjustment clause; 3) retail electricity prices rising faster than overall consumer price inflation; 4) electric generation rising faster than the overall economy; and 5) strong electric capacity growth.

Mr. Bohrmann indicated that state public utility commissions, including Oklahoma's Commission, have established criteria to determine whether a type of cost qualifies for recovery outside of base rates. In order for a cost to qualify for a recovery outside of rate base, he testified, it must meet all three of the following criteria: The cost must be 1) substantial; 2) volatile; and 3) outside the utility's control. Mr. Bohrmann also detailed why a utility is incentivized to shift risks from itself to its ratepayers by moving as many costs as possible from base rates to an adjustment mechanism like PSO's Fuel Clause.

Mr, Bohrmann posits that the Company's fuel procurement, unloading, and handling costs fail at least two of the three criteria for cost recovery outside of base rates. Mr. Bohrmann shows that these costs were neither significant (less than 0.3 percent of the Company's total operating revenues) nor outside PSO's control. Mr. Bohrmann also asserts that recovery of PSO's fuel procurement, unloading, and handling costs through base rates would promote better cost discipline over those costs. Finally, Mr. Bohrmann's recommendation is revenue-neutral to PSO. His testimony focuses exclusively on the appropriateness of recovering this expense through base rates instead of through the fuel adjustment clause. Mr. Bohrmann does not address the prudence that the Company exercised in incurring this expense.

Mr. Bohrmann also recommends that the Commission reject the Company's proposed change to its TA Rider for several reasons. First, PSO's proposed change to its TA Rider does not pass the well-established three-prong test used to determine whether a cost should be eligible for recovery through an adjustment mechanism outside of base rates. Mr. Bohrmann explained that property (ad valorem) taxes are 1) not substantial; 2) not volatile; and 3) within PSO's control. Mr. Bohrmann showed that property (ad valorem) taxes are neither substantial nor volatile when compared to the Company's total operating income or its gross plant in service. Also, he explained, although PSO does not set property (ad valorem) tax rates, PSO exercises significant control over the amount of property (ad valorem) tax the Company pays during any given year. For example, when the Company must increase its power resources to meet its native load reliably, the Company makes several decisions that can impact property (ad valorem) taxes paid, such as 1) choosing whether to build incremental generation plant, or purchase wholesale capacity and associated energy from another load-serving entity or merchant generator; and 2) choosing the type, timing, location, and size of the incremental generation. Mr. Bohrmann testified that, for incremental transmission and distribution plant, the Company can exercise control over the type, timing, path, and size of these incremental resources that can impact its property (ad valorem) taxes paid. For incremental general plant, he explained, the Company can exercise control over the type, timing, location, and size of these incremental resources that can impact its property (ad valorem) taxes paid. Mr. Bohrmann concluded, based on the foregoing considerations, that ad valorem taxes are ineligible for a rider.

Mr. Bohrmann also identified three structural flaws with the Company's proposed change to its TA Rider. First, he explained that the proposed change only examines the change in one specific cost type – property (ad valorem) taxes – without examining the extent to which all of the Company's costs recovered through base rates may change. Second, he noted that the proposed change does not consider the impact that growth in customers, energy, and demand between rate cases will have on base rate revenues. Third, he testified that the Company's proposal shifts the risk of changes to property (ad valorem) tax paid between rate cases from PSO to the ratepayers, and offers nothing in return to the ratepayers for assuming this risk, such as a lower return on equity.

Mr. Bohrmann indicated that PSO's forecast of customer, energy, and demand growth, as well as its capital expenditure forecast for the next three years, are expected to place upward pressure on the Company's property (ad valorem) taxes paid, all other factors being equal. He explained that, between rate cases, the Company is better equipped than the ratepayers to minimize the property (ad valorem) taxes the Company will pay. Mr. Bohrmann posited that property (ad valorem) tax paid regarding the Company's proposed Wind Catcher project would not be collected under the TA Rider, as proposed by PSO. Mr. Bohrmann disagrees with PSO that it is in the best interest of its ratepayers and itself that the ratepayers pay exactly what PSO pays in property (ad valorem) tax. Between rate cases, Mr. Bohrmann testified, the Commission relies upon the Company's prudence, judgment, and business acumen to manage its affairs appropriately, so that the Company may have an opportunity to earn a fair rate of return based on base rates set forth in the most recent rate case. When the Company's base rates can no longer support a fair rate of return, the Company may initiate a rate case proceeding, Mr. Bohrmann explained. He testified that the Commission neither has the obligation, nor should it have the interest, in micromanaging the Company's finances so precisely, as proposed by the Company. For these additional reasons, Mr. Bohrmann recommended that the Commission reject PSO's proposed change to its TA Rider.

EDWIN C. FARRAR

Mr. Edwin C. Farrar pre-filed responsive rate design testimony on behalf of Mike Hunter, Oklahoma Attorney General. Mr. Farrar's recommendations addressed the allocation among customer classes of any increase in Public Service Company of Oklahoma's ("PSO") rates that may be ordered by the Oklahoma Corporation Commission ("Commission").

Mr. Farrar testified that PSO is recommending that subsidies between, but not within, customer classes, be eliminated. He further noted that PSO's requested rate increase and proposed collection thereof from customers would increase residential rates by nearly 14%, or approximately $14 per month for a typical residential customer. Mr. Farrar stated that a residential increase of $14 per month totals $156 per year, which is the equivalent cost of electric power for one and one-half months under current rates.

Mr. Farrar stated that the Attorney General has recommended a significant reduction to PSO's requested $169.7 million rate increase, and if the Commission adopts the Attorney General's recommended revenue requirement, then the Attorney General would support a move of each customer class to its full and true cost of service, provided some additional provisions are included. Mr. Farrar said that the Attorney General supports moving each customer class to its true cost of service, but that the impact of this effort is magnified when a rate increase grows in magnitude. For that reason, it is the Attorney General's position that the move to the true cost of service for each customer class only occur if the Commission adopts the Attorney General's revenue requirement recommendation. Otherwise, if the Commission orders a revenue requirement for PSO that is greater than that recommended by the Attorney General, Mr. Farrar recommended that the resulting rate increase should be applied proportionally for all customers, meaning that all customer classes' rates are increased by the same percentage.

Mr. Farrar testified regarding the additional provisions that the Commission should observe in moving customers to their full cost of service. These provisions include the following: 1) eliminating intra-class subsidies; 2) maintaining the current rates of customers that are already above their full revenue requirement; and 3) limiting rate impacts on public schools and municipal street lighting customer classes to the extent that those classes cover their non-return revenue requirement.

Mr. Farrar also testified that the Attorney General supports PSO's proposal to apply any rate increases that the Commission may order to the volumetric and demand charges, while avoiding increases to the monthly customer charge, as PSO's monthly customer charge is the highest among investor owned utilities regulated by the Commission.

Mr. Farrar discussed PSO's Class Cost of Service Study ("CCOSS"). He stated that a CCOSS is an analytical tool used to evaluate the financial burden each customer class places on the utility system. Mr. Farrar testified that the assumptions used to prepare the CCOSS are determined judgmentally based on the operating characteristics of the utility, and because of that, a CCOSS, like every analysis used in setting rates, is part art and part science. Mr. Farrar updated the PSO CCOSS to include the impact of revenue requirement adjustments proposed by the Attorney General, but made no other changes to the CCOSS. Mr. Farrar did not address any specific issues related to PSO's CCOSS methodology, and took no position on the merits of the CCOSS or its methodology.

Mr. Farrar discussed the results of updating the CCOSS with the Attorney General's revenue requirement recommendations, which included an $86.4 million reduction to the PSO proposed base rate increase of $169.7 million. Mr. Farrar testified that the Attorney General's recommendations included removing from consideration $23.8 million of rider revenue that PSO proposed be recovered in base rates, as well as the Attorney General's proposal to move $3.2 million of fuel costs moved from the Fuel Adjustment Clause ("FAC") into base rates, less $0.2 million in adjustments affecting the base rate fuel costs.

Mr. Farrar noted that certain rates would be reduced if the Attorney General's adjusted CCOSS is strictly followed, but that those decreases to a few customers would be inappropriate if most other customers receive a substantial rate increase. Instead, Mr. Farrar recommended that the current rates be maintained for those customers, and that the revenue available from maintaining the current rates for those customers be allocated to the two public school rate classes and to the municipal street lighting rate class. This change should be applied first to the public school rate classes, but only to the extent that those classes cover their non-return revenue requirement, with the balance applied to the municipal street lighting rate class. All three of those customer rate classes are governmental public service entities that benefit other customer groups and the public at large.

Mr. Farrar sponsored Exhibit ECF-RD-1, which shows the results of his rate design recommendations for the various customer classes.

JAMES B. ALEXANDER

James B. Alexander submitted pre-filed responsive rate design testimony on behalf of Mike Hunter, Oklahoma Attorney General. Mr. Alexander, a regulatory analyst employed by the Attorney General, testified regarding a change to the treatment of off-system sales of electricity in the Fuel Adjustment Clause of Public Service Company of Oklahoma ("PSO").

Mr. Alexander explained how PSO's off-system sales of electricity historically have been handled from a regulatory perspective. He noted Load Serving Entities were responsible for their own balancing of generation and load, and the incentive of sharing a portion of off-system sales of electricity would work to ensure excess capacity would be sold through bilateral trades. Such incentives might have been advisable prior to the implementation of the Southwest Power Pool ("SPP") Integrated Marketplace. He also noted that the issue has been a topic of discussion in the two previous rate cases.[4] Moreover, Mr. Alexander noted that, in the 2015 PSO rate case, the Oklahoma Corporation Commission ("Commission") reduced PSO's share of off-system sales margins from 25 percent to 10 percent.[5]

Mr. Alexander recommended that the incentive component of PSO's FAC Rider be removed and that 100 percent of off-system sales of electricity be credited to PSO customers.

First, Mr. Alexander explained that the SPP Integrated Marketplace now handles the dispatch of units within the region. Mr. Alexander explained that having the incentive, while SPP is responsible for the dispatch of units, could motivate improper unit management. He noted that PSO does make decisions that depart from SPP dispatch directions due to PSO's use of a seven-day forecasting period, but added that the extended use of self-commitments could lead to penalties from the marketplace. Mr. Alexander explained additional ways the incentive could disadvantage customers, including the over-developing of resources. Further, he explained that, if PSO is able to use resources paid for by customers to engage in transactions on the SPP marketplace, PSO may have an incentive to secure additional generating resources that may not be necessary to provide service to customers at the lowest reasonable cost.

Second, Mr. Alexander explained the market rates provided by the SPP Integrated Marketplace allow for an accurate check on the costs accrued by PSO. He stated that, prior to the Integrated Marketplace, reasonable costs may have been much more difficult to determine. The Integrated Marketplace allows for a "market rate" check to be used by the Commission and its staff to compare and find a reasonable rate. He stated that all of the generation resources PSO currently uses should be reviewed as part of the fuel adjustment clause review process. He also noted that costs which are not reasonable should be disallowed by the Commission.

Third, Mr. Alexander explained that regulators should generally treat Oklahoma utilities and their customers in a fair and similar manner, absent distinctions suggesting otherwise. He noted that neither Oklahoma Gas & Electric Company ("OG&E") nor The

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[4] *See* Responsive Test. of Sharon Fisher on Behalf of Public Utility Division, *Application of Pub. Serv. Co. of Okla. to be in Compliance with Order No. 591185*, Okla. Corp. Comm'n No. PUD 201300217, 10 (Apr. 23, 2014); *See* Rate Design Test. of Mike Garrett on behalf of OIEC, *Application of Pub. Serv. Co. of Okla. to be in Compliance with Order No. 591185*, Okla. Corp. Comm'n No. PUD 201300217 (Apr. 23, 2014), 42; *See* Rebuttal Test. of Naim Hakimi on behalf of Public Service Company of Oklahoma, *Application of Pub. Serv. Co. of Okla. to be in Compliance with Order No. 591185*, Okla. Corp. Comm'n No. PUD 201300217, 5 (May 29, 2014).

[5] Final Order, Order No. 657877, *Pub. Serv. Co. of Okla. Rates and Charges for Elec. Serv.*, Okla. Corp. Comm'n PUD 201500208, 11 (Nov. 10, 2016).

Empire District Electric Company ("Empire") receive returns on off-system sales of electricity. He discussed OG&E's 2011 rate case settlement agreement that ended OG&E's recovery of off-system sales margins,[6] noting that OG&E's expert on this subject in that case had testified that the month-to-month adjustments had created volatility with a negative effect on the monthly bills of a portion of its customer base. Mr. Alexander then explained his position that all Oklahoma utility customers' investments should be handled by the Commission in the same manner, unless there is a specific reason not to do so. He found no reason for the disparate treatment between PSO and other Oklahoma utilities in this regard, noting the inequity resulting from PSO customers paying for an incentive, while OG&E is expected to provide service at the lowest reasonable cost to its customers without such an incentive.

STATEMENTS OF POSITION

AARP

COMES NOW AARP, by and through its undersigned counsel, and hereby provides its Statement of Position describing the positions that AARP in this proceeding.

AARP, with its nearly 38 million members in all 50 States and the District of Columbia, Puerto Rico, and U.S. Virgin Islands, is a nonpartisan, nonprofit, nationwide organization that helps people turn their goals and dreams into real possibilities, strengthens communities and fights for the issues that matter most to families such as healthcare, employment and income security, retirement planning, affordable utilities and protection from financial abuse. AARP has 400,000 members residing in Oklahoma representing all segments of the socio-economic scale. Moreover, a substantial percentage of AARP's members live on fixed or limited incomes and depend on reliable electric service for adequate heat, cooling and lighting.

Affordable and reliable electric service is required for economic security, health, and personal welfare. Older adults are particularly burdened by price increases on energy, as many of them live on fixed incomes and lack the flexibility to pay significantly higher monthly expenses and average utility expenditures for households headed by people age 65 and older have been rising faster than inflation.

AARP respectfully requests the Commission evaluate the evidence submitted in this matter and make determinations consistent with the following.

1. **PSO should be granted a return on equity of 8.83%.**

While PSO requested an ROE of 10.50% in its last rate case, PSO's current rates are based on a return on equity (ROE) of 9.50% as established in Order No. 657877. Based on all the calculations submitted in this case, it appears since the last PSO rate case, returns have declined. The Oklahoma Attorney General has calculated a reasonable return at 8.83%, while the Public Utility Division has provided evidence to support an ROE of 8.90%. In this case,

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[6] Final Order, Order No. 599558, *Okla. Gas and Elec. Co. Rates and Charges for Elec. Serv.*, Okla. Corp. Comm'n No. PUD 201100087, 17 (July 9, 2012).

PSO is seeking an ROE of 10.00% but no party--other than the utility--recommends a ROE higher than 9.00%.[7]

Therefore, based on the evidence submitted to the Commission, AARP recommends and supports a determination of a ROE of 8.83% as fair, just and reasonable in setting rates for PSO in this case.

2. Northeastern Unit No. 4 is no longer "used and useful" as required by law and, therefore, PSO should not recover further costs from ratepayers.

PSO retired its coal generation plant Northeastern Unit 4 (NE4) in April 2016 pursuant to a voluntary agreement the utility made to settle its compliance with certain environmental regulations. It should be noted that no regulations required the specific retirement of NE4 and that such approach to meet regulatory requirements was made by PSO management. To serve its customer's needs, PSO has subsequently replaced the capacity formally generated by NE4 with other resources. PSO is seeking to continue to recover the cost of NE4 and a full return for its shareholders from ratepayers.

NE4 is no longer "used and useful" as it was not providing service to customers in the test year and there is no plan for its use in the future, that is, NE4 is no longer being used to provide service and is not contributing to the provision of service. To date, shareholders have recovered a significant amount of the initial investment plus a return for NE4 from ratepayers over the 46-year life of NE4 (well beyond its original retirement date). It should also be noted that customers have continued to pay for NE4 in rates in both 2016 and 2017, and will continue to do so until new rates are established, even though it has been retired for more than a year and a half.

Moreover, the utility is now recovering from ratepayers additional return for assets that have replaced the capacity formerly provided by NE4. To allow recovery of the retired asset that is no longer in service and the new assets that replaced the retired unit, amounts to requiring ratepayers to pay twice (and shareholders to receive even more profits) for the same amount of capacity serving their needs. At this point, the remaining balance of the plant may need to be written down or off by the utility and shareholders can reduce the impact with the associated tax treatment.

Therefore, because Northeastern Unit 4 is not used and useful, did not provide service to customers during the test year, and the utility has replaced this capacity which is being recovered in rates, the Commission must reject further recovery of NE4 in rates.

3. The Commission should reject PSO's attempt to expand its existing Tax Adjustment Rider.

In addition to recovery of its ad valorem taxes in the amount of $35,779,771.00 in its base rates, PSO is also seeking to expand its existing Tax Adjustment Rider to provide for

[7] As to the remaining parties, OIEC recommends an ROE of 9.00, while the U.S. Dept. of Defense recommends an ROE of 8.00%.

additional recovery in order to true up ad valorem taxes from customers outside of established rates. PSO's only justification for this new rider treatment is that PSO wishes to eliminate the "mis-match" in annual ad valorem taxes.

The Commission's criteria in determining potential need for rider recovery is that riders should only be considered if they are used for costs that are outside of the utility's control, substantial, and unpredictable or volatile. PSO has failed to demonstrate or even address in its testimony that any true up of ad valorem taxes from year to year outside of rates is substantial, unpredictable or volatile. PSO's requested ad valorem true-up is not by any measure substantial, is not unpredictable and is not volatile. Therefore, PSO's request for this expansion of the Tax Adjustment rider fails.

Moreover, the type of treatment PSO seeks constitutes piecemeal ratemaking in that it fails to consider all expenses and revenues that can be identified and evaluated as is done in a rate case. PSO's proposed rates in this case already reflect full recovery of ad valorem taxes and any recovery of differences through a rider without any accounting for additional revenues or lowered expenses is an unjustified windfall to shareholders. This is in fact the "mismatch" that should be avoided.

Therefore, the Commission should reject PSO's unsupported request to expand its Tax Adjustment Rider to include a true-up provision for ad valorem taxes which are already recovered in base rates.

4. AARP supports the termination of the AMI Rider and the System Reliability Rider (SRR).

The costs to provide utility service should not be collected through piecemeal surcharges in the form of riders, but rather through base rate where all expenses and revenues are identified and evaluated prior to allowing cost recovery. Riders also result in additional undesirable consequences such as removing utility incentives to control costs and improperly shifting utility business risks away from the company (who are in a position to identify and address such risks) and onto ratepayers. Thus, riders should only be approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if not addressed outside of a base rate case, could harm a utility's financial health.

PSO has continued to collect AMI charges through a rider without review of the prudence of those costs and now seeks to terminate the rider and move these costs into base rates. Moreover, in PSO's last rate case, Order No. 658529 allowed PSO to continue to collect unrecovered capital costs outside of base rates for the SRR. In a rate case, prior to recovery in rates, the utility has the burden to demonstrate the prudence of such investments. As such, the Commission should only approve recovery of those items that PSO has proven are prudent investments prior to the inclusion in base rates.

Therefore, AARP supports the termination of the AMI Rider and the System Reliability Rider and move recovery of such costs into base rates, provided the Commission finds affirmatively that PSO has proven the prudency of all such investment and expense prior to any recovery in base rates.

5. **<u>The Commission should continue to disallow 50% of short-term incentive compensation and 100% of long-term incentive compensation, which are contingent in nature and based solely on financial earnings of the shareholders.</u>**

PSO is once again requesting the Commission modify its long-standing policy – similar to many other jurisdictions - that treats incentive compensation tied to financial performance of the company (normally in the form of increased earnings) as a below-the-line expense that is not included in formulating base rates. Our Commission only allows recovery of 50% of short-term incentives and none of the costs of long-term incentives or Supplemental Executive Retirement Plans. It should be noted that surrounding states (along with a long list of others) have similar treatment of disallowing discretionary incentive pay that is tied to financial performance, and for good reason.

First, it is not proper to set ongoing rates based on unknown/contingent levels of expenses (i.e., not known and measurable). PSO has no obligation to pay out any incentive compensation in any given year. Commissions don't include this type of compensation in rates because it is discretionary and can be retained by shareholders to boost earning. Specifically, PSO has no obligation to pay any incentives if earnings do not achieve certain internally set targets. In fact, PSO's incentive plan says that they use earnings targets to determine whether or not to even pay out incentives in the first place because it insures that the company's commitment to earnings targets are met for shareholders prior to paying any incentives to employees.

Second, commissions regularly exclude expenses that do not directly benefit ratepayers. Examples of this include lobbying, charitable contributions, certain advertising, benefits tied to increased earnings, and special execute compensation. Shareholders, not ratepayers, benefit from company incentives to increase earnings. Because shareholders benefit, shareholders pay. Of course, utilities design these programs such that the targeted increased earnings are sufficient to pay for the incentives, meaning they are funded with some portion of the extra earnings the company achieves. That is why, as described above, the company does not commit to pay out a single dollar until shareholders' financial goals are met.

Third, the company is not prevented nor is it disadvantaged by this standard below-the-line treatment. The Commission's own history demonstrates this fact. Like many utilities, neither OG&E nor PSO have these expenses included when setting rates, yet each of them has established incentive programs and continue to pay out (or not) based on the earnings of the company. Whether or not such recovery is reflected in rates has absolutely no impact on whether or not shareholders find such incentives financially beneficial. In addition, Oklahoma utilities are treated the same as other similarly situated utilities so there is no basis for the claim that PSO is disadvantaged by this standard regulatory treatment.

PSO fails to provide evidence of any type of change in circumstance that would justify a variation in the regulatory ratemaking treatment of these expenses. Of course, incentive compensation is part of a total compensation package – no change there. Of course, it is part of attracting and retaining personnel – again no change there. Of course, other utilities offer incentive compensation – no change there. What also has not changed, is that commissions treat these expenses as below-the-line and do not include them in establishing rates. In fact, it is so routine that these types of expenses are excluded that many commissions don't even need to address this issue over and over again.

Therefore, AARP supports the continued below-the-line treatment of 50% of short-term incentive compensation and 100% of long-term incentive compensation from rates, which are contingent in nature and based solely on financial earnings of the shareholders.

6. **The Commission should reject PSO's request to quadruple the amount of storm expense included in base rates.**

PSO's rates have historically included a buffer amount of storm-related O&M in the amount of $2.87M. PSO is then authorized to collect all additional storm expenses beyond this amount through the establishment of a regulatory asset. In addition to this treatment, PSO is requesting to quadruple the amount of funds for future potential storms in rates from $2.87M to $11.2M, as well as maintain the ability to recover any additional expenses through a regulatory asset. AARP does not object to the inclusion of $2.87M in base rates as is reflected in rates today, but does object to PSO's request to quadruple that amount for future unknown storms, especially when PSO (as described in its testimony) already has an approved methodology to recover any years with any additional storm-related O&M.

Storm expense can vary significantly from year to year, from less than a million dollars to tens of millions of dollars in another. It should be noted that through various riders, customers have funded significant vegetation management efforts, installment of smart meters, undergrounding efforts of critical lines, etc., all supposedly to help PSO improve its system and its reliability. These investments should benefit customers through lower damage and expenses during future storms on PSO's system. Based on these customer-funded improvements, the amount currently reflected in base rates should not be going up as PSO's system improvements should work to limit expenses it might otherwise encounter.

Therefore, AARP objects to PSO's request to include $8.624M over and above the approved $2.87M for future storm-related O&M, particularly when PSO already has a mechanism to recover any additional expense in any given year using a regulatory asset and then full recovery thereof.

7. **PSO should remove all distribution costs embedded in its fixed monthly charge resulting in its inflated monthly Base Service Charge.**

The use of a fixed monthly "customer charge" was developed for utilities to recoup costs related solely to customer-related costs, which include items such as metering and billing that are directly tied to the number of customers served. As the Commission has heard ad nauseam in recent cases, a monthly "customer charge" was NOT developed recover distribution, transmission or generation costs, as those costs are normally recovered in the variable kilowatt hour charge.

The Commission previously approved the exorbitant monthly charge for PSO customers at $20.00 per month– one of the highest monthly charges in the country – in Cause

No. PUD 2013-217 by inappropriately allowing PSO to shift certain distribution costs into a fixed monthly charge.

Moreover, the Commission has had a chance to review this issue and its impact in several recent rate cases for both OG&E and Empire and rejected both utilities' attempt to shift costs to the fixed charge. Unfortunately, PSO's customers have not been protected from this move and pay an excessive fixed monthly charge. AEP's other jurisdictions have monthly service charges ranging from $7.30 to $11.00 per month, much lower than the charge of $20.00 per month to which Oklahoma ratepayers are subjected.

AARP requests the Commission direct PSO to re-run its cost of service to remove all distribution-related charges from its fixed monthly Base Service Charge computation and calculate customers' true monthly fixed charge by allocating only metering and billing costs.

CONCLUSION

AARP respectfully requests the Commission, after consideration of the evidence in this matter, make the following determinations in this cause:

1. **PSO should be granted a return on equity of 8.83%.**

Based on the evidence submitted to the Commission, AARP recommends and supports a determination of a ROE of 8.83% as fair, just and reasonable in setting rates for PSO in this case.

2. **Northeastern Unit No. 4 is no longer "used and useful" as required by law and, therefore, PSO should not recover further costs from ratepayers.**

Because Northeastern Unit 4 is not used and useful, did not provide service to customers during the test year, and the utility has replaced this capacity which is being recovered in rates, the Commission must reject further recovery of NE4 in rates.

3. **The Commission should reject PSO's attempt to expand its existing Tax Adjustment Rider.**

The Commission should reject PSO's unsupported request to expand its Tax Adjustment Rider to include a true-up provision for ad valorem taxes which are already recovered in base rates.

4. **AARP supports the termination of the AMI Rider and the System Reliability Rider (SRR).**

AARP supports the termination of the AMI Rider and the System Reliability Rider and move recovery of such costs into base rates, provided the Commission finds affirmatively that PSO has proven the prudency of all such investment and expense prior to any recovery in base rates.

5. **<u>The Commission should continue to disallow 50% of short-term incentive compensation and 100% of long-term incentive compensation, which are contingent in nature and based solely on financial earnings of the shareholders.</u>**

AARP supports the continued below-the-line treatment of 50% of short-term incentive compensation and 100% of long-term incentive compensation from rates, which are contingent in nature and based solely on financial earnings of the shareholders.

6. **<u>The Commissions should reject PSO's request to quadruple the amount of storm expense included in base rates.</u>**

AARP objects to PSO's request to include $8.624M over and above the approved $2.87M for future storm-related O&M, particularly when PSO already has a mechanism to recover any additional expense in any given year using a regulatory asset and then full recovery thereof.

7. **<u>PSO should remove all distribution costs embedded in its fixed monthly charge resulting in its inflated monthly Base Service Charge.</u>**

AARP requests the Commission direct PSO to re-run its cost of service to remove all distribution-related charges from its fixed monthly Base Service Charge computation and calculate customers' true monthly fixed charge by allocating only metering and billing costs.

AARP reserves the right to amend, modify or supplement its position in the docket, to cross examine witnesses on all issues, to request any affirmative relief, and to address any and all issues raised at the hearing on the merits necessary to protect its interests in this matter.

OKLAHOMA HOSPITAL ASSOCIATION

I. INTRODUCTION

Oklahoma Hospital Association ("ORA") provides its Statement of Position describing the positions that ORA recommends the Commission adopt in this proceeding.

Established in 1919, OHA represents the interests and views of more than 135 member hospitals and health systems across the state of Oklahoma. ORA's primary objective is to promote the health and welfare of all Oklahomans by leading and assisting its member organizations in providing high quality, safe, and value-based health care services to their communities. ORA also believes hospitals play a vital role in helping to advance the overall state of health for their patients and the public at-large. OHA provides a variety of member services including representation and advocacy at the state and federal levels, educational projects, information and data analysis, patient quality and safety resources, and industry communication.

OHA participates in general rate cases on behalf of its members because these cases offer an opportunity for regulators to conduct a full and complete review of a utility's actual costs to provide service, and to ensure that the rates OHA members pay are fair, just, and reasonable.

A. OHA'S POSITIONS

1. Revenue Allocation

OHA agrees with the proposed revenue allocation methodology of PSO, OIEC, Wal-Mart/Sam's, and the Department of Defense which would allocate any rate increase stemming from this case to each major rate class to match its cost of service. To the extent the Commission determines a lower overall revenue requirement is necessary than that requested by PSO, any resulting increase should be allocated such that each class pays its own costs.

Utilities can estimate the cost of serving its various rate classes by functionalizing and classifying its costs, and then allocating them to the rate classes in a way that reflects what causes different costs. This process determines the difference between revenues and costs among customer classes, which is the percentage rate of return from each class. Classes earning equal to the system requested rate of return show that the class is actually paying the cost of serving it. If a class is actually paying more than the average rate of return, that result generally indicates that its revenues are greater than costs allocated to it. The relative rates of return provide a great deal of information, as relatively lower rates of return will require relatively higher percentage increases for revenues to equal costs. Based on the results of an allocated cost study, it is prudent to design rates such that each class is paying its full costs, and only its full costs.

Rates should signal to customers the cost of their usage so that customers can make economic decisions. For instance, rates can inform customers that it is more expensive to produce electricity during some seasons and during some hours than in others. It is obvious that if an entire rate class is paying less than the cost of serving it, customers in that class are not receiving proper price signals. Applying a cost-based approach to revenue allocation in this rate case will correct the historic undercharging of some rate classes and the overcharging of others. Indeed, all parties who filed testimony in this case on the subject of rate design and cost allocation have advocated for the goal of moving classes toward cost-based rates. While the Commission's PUD and the Attorney General have offered a less deliberate move toward class parity based on the overall level of rate increase (see Cost of Service and Rate Design Testimony of Jeremy K. Schwartz for PUD, Cause No. 201700151, pp. 19-21 (Oct. 3, 2017) (advocating gradual move toward parity based on large rate increase); Rate Design Testimony of Edwin C. Farrar for the Oklahoma Attorney General, Cause No. 201700151, p. 4 (Oct. 3, 2017) (advocating cost-based rates up to the revenue requirement proposed by the Attorney General)); all other parties filing testimony have advocated for a complete move to cost-based rates (see Responsive Testimony of Larry Blank on Cost of Service and Rate Design Issues for the Department of Defense, Cause No. 201700151, P. 8 (Oct. 3, 2017) (advocating PSO's proposal to achieve parity among classes); Responsive Rate Design Testimony of Mark E. Garrett for OIEC, Cause No. 201700151, p. 12 (Oct. 3. 2017) (advocating cost-based rates for all classes); Responsive Cost of Service and Rate Design Testimony of Steve W. Chriss for Wal-Mart/Sams, Cause No. 201700151, p. 5 (Oct. 3, 2017) (advocating for cost-based rates for all classes).

Many of OHA's member hospitals in the PSO territory are in rate classes and rate schedules that are paying higher than average rates of return. If the Commission does not apply cost-based rates in this case, it will mean that the hospitals will continue to pay more than costs for the electric service used in conjunction with treating patients and operating facilities. Charging hospitals more than costs is particularly bad public policy considering the vital role OHA members play in providing medical services in the state. Hospitals provide a vital public function and are not an inexhaustible resource of revenue to satisfy electric rate increases. Excessive electric charges put upward pressure on the costs of medical services used by many of the very same residential customers who have been spared larger increases in electric bills in the past.

OHA requests that the Commission adopt PSO's proposed methodology in this rate case by applying any rate increase in a manner that achieves cost-based rates.

2. Return on Equity

PSO has requested a 10% return on its equity in this case, an increase from 9.5% granted in PSO's previous rate case, Cause No. 201500208. Meanwhile, proposed ROEs from Intervenors range from 8.0% (Department of Defense) to 9.0% (OIEC/Wal-Mart/Sam's). Within this range falls the Commission's Public Utility Division (8.9% ROE) and the Attorney General (8.83% ROE).

It is notable that none of the above-listed proposals approach the 10% ROE requested by PSO. While PSO is entitled to earn a reasonable return on its investment, it is not entitled to earn an inflated return. Based on the filed testimony, OHA recommends the Commission adopt the 8.83% return on equity advocated by the Attorney General, which falls closest to the mean value of the four recommended ROEs proposed by Intervenors.

3. Rate Adjustments

Aside from the issue of Return on Equity, OHA recommends that the Commission adopt adjustments proposed by OIEC as reflected in MG-2, attached to the Responsive Testimony of Mark Garrett, filed September 21, 2017. These include adjustments to Rate Base, decreasing annual revenues ($14,714,695); adjustments to Operating Expense, decreasing annual revenues ($50,659,374); and adjustments to Depreciation Expense, decreasing annual revenues ($33,203,148).

B. CONCLUSION

OHA's failure to address any of the issues presented by the parties in this case should not be taken as objection or support for any specific positions. OHA reserves the right to amend, modify or supplement its position in the docket, to cross-examine witnesses on all issues, and to address any and all issues raised at the hearing on the merits necessary to protect its interests in this matter.

REBUTTAL TESTIMONY

Public Service Company

RANDALL W. HAMLETT

In rebuttal testimony, Mr. Hamlett testified that PSO has retired Northeastern Unit 4 and it has been removed from plant in service. Transferring the under depreciated value to a regulatory, asset as recommended by PUD, is reasonable and is consistent with past OCC precedent as it relates to old meters replaced by AMI meters. The AG and OIEC recommendations would result in write-offs and should not be accepted.

According to Mr. Hamlett, allowing for the inclusion of the environmental deferral asset through the date new rates will be implemented is a mathematical exercise and reflects a known and measurable change to the test year amount. If the amount is limited to the six-month post-test year amount, Ms. Weber has provided the correct amount exclusive of carrying costs. Carrying costs on the regulatory asset is appropriate and consistent with Order No. 657877 issued in Cause No. PUD 201500208.

The Company agrees that other regulatory assets and regulatory liabilities should be updated for six-month post-test year data recognizing Ms. Weber is the only witness providing the correct environmental deferral regulatory asset pre carrying costs.

Mr. Hamlett further testified, PUD has correctly provided the six-month post-test year update value of prepayments. The pension prepayment amount excluded by the AG and OIEC was included in rate base in Cause No. PUD 201500208 and it is not appropriate to disallow the previously included costs. The amount they recommend be removed from rate base is verifiable contrary to their testimonies.

Mr. Hamlett further testified that the Company agrees that accumulated deferred income taxes (ADIT) should be updated for six-month post-test year values which were provided by PUD and OIEC. AG's recommendation does not reflect the amount on PSO's books and records.

The Company agrees with the six-month post-test year adjustments to plant in service and accumulated depreciation.

OIEC's recommendation to reduce rate base for capitalized incentives back to the year 2000 is not consistent with past OCC decisions and inappropriately removes costs that have previously been included in rate base, namely amounts through the last case, Cause No. PUD 201500208.

Mr. Hamlett also testified that other six-month post-test year amounts for materials and supplies, fuel inventory, off-system trading deposits, customer deposits, non-refundable contributions in aid of construction (CIAC) are appropriate. Finally, cash working capital should be synchronized with the final decision in this case.

PSO's adjustment to payroll represents a known and measurable adjustment that PUD agrees with. The analysis presented by the AG and OIEC was not based on total payroll and is not an accurate presentation. The 5.2% change presented by AG and OIEC is not an annual number and represents two years of pay increases.

Supplemental Executive Retirement Plan (SERP) applies to all employees that exceed the Internal Revenue Code limitations and not just executives. The SERP does not provide any additional benefits beyond a standard retirement pension contribution consistent with the salary of the employee. The distinction between qualified plans and SERP plans relates only to their treatment under the Internal Revenue Code, and has nothing to do with the reasonable nature of both classifications of retirement plans.

PSO's adjustment to Southwest Power Pool (SPP) expenses is known and measurable as confirmed by PUD. PSO supported the adjustment in discovery with multiple tab spreadsheets that were verified by PUD with outside data available from the SPP. The calculation of this adjustment is consistent with the adjustment approved in Cause No. PUD 201500208.

The amount of storm costs included in base rates is almost ten years old and needs to be updated to recognize more current amounts. PUD recommendation is consistent with a past decision and provides a reasonable update that can be revisited in the future as additional data becomes available.

According to Mr. Hamlett, the environmental deferral regulatory asset amortization should be synchronized with the final amount included in rate base. The Company agrees with PUD's accretion expense adjustment. PUD's intangible amortization considers data beyond the six-month post-test year that decreases expense but fails to consider items that would increase the expense. This adjustment is also inconsistent with PUD's recommendation regarding other items that were cut off at six-month post-test year. PUD amortization of their recommended Northeastern Unit 4 regulatory asset should begin when new base rates are implemented in this case and not prior to that date because PSO's current rates were not designed to collect these costs. The Company agrees with PUD's meter regulatory asset amortization. The company's five year amortization for software is consistent across the AEP system and has been approved by OCC. As warranted, the Company does utilize different amortization periods. OIEC contradicts itself by saying depreciation is timing and the commission is better served to over-estimate depreciable lives and then when that happens for Northeastern Unit 4, they recommend the Company write-off the undepreciated value.

Factoring expense and income tax expense should be synchronized with the final revenue requirement in this case.

PSO provided a reasonable estimate of rate case expenses and will true-up actual expenses to the estimated expenses in this case. PSO does not oppose a three year amortization period in this case.

PSO does not oppose PUD's adjustment to dues and donations.

Mr. Hamlett testified that it is not appropriate to include a non-recurring gain related to the sale of property as recommended by PUD.

The large credit in Federal Energy Regulatory Commission (FERC) Account 557 is related to PSO's over/under recovered fuel. Refunds and surcharges of over or under recovered fuel are handled in the Fuel Adjustment Clause (FAC). OIEC's recommendation for a refund of this item in this case should be rejected since the FAC already addresses this issue.

In response to Mr. Farrar, securitization in Texas is done pursuant to Texas Statute according to Mr. Hamlett.

Phase-in plans raise red flags from an accounting perspective and may not result in deferrals for financial reporting purposes.

Mr. Hamlett testified that Ms. Weber's recommendation was a reasonable alternative to the Company's filing because it provides a return of and on the undepreciated value of Northeastern Unit 4 and is acceptable to PSO with one minor modification. Amortization of the recommended regulatory asset should begin on the date new rates are established from this proceeding instead of July 1, 2017, as recommended by Ms. Weber. Under Ms. Weber's recommendation the Company should be amortizing the regulatory asset today even though the Commission has not ruled on her recommendation.

In response to Mr. Bohrmann and Mr. Mark Garrett, Mr. Hamlett testified that from an accounting perspective, Northeastern Unit 4 was retired in April 2016, and the asset was entirely removed from PSO's book and records, and accordingly from utility plant in its rate base, using standard FERC Uniform System of Accounts (USofA) Electric Plant Instructions 10.B.(2) retirement entries. However, it is undisputed in this proceeding that applying the OCC's approved depreciation rates over time in PSO's base rates has not allowed recovery of the full book value of Northeastern Unit 4 at the time of its retirement. As such, the remaining undepreciated value of Northeastern Unit 4 resides in FERC Account 108 Accumulated Depreciation.

According to Mr. Hamlett, PUD witness Ms. Weber states on page 35, lines 17 through 20, of her responsive testimony that PSO's reclassification to a sub-account within accumulated depreciation was in accordance with FERC instructions.

According to Mr. Hamlett, beginning in January 1982, depreciation rates approved by the OCC, based upon a 1980 depreciation study, were implemented with an estimated useful life of approximately 31 years. In 1996, the Commission approved depreciation rates that contained an estimated useful life of 42 years. The last time the estimated useful life was updated was in 2006, where the Commission adopted a 60 year useful life.

Mr. Hamlett testified that the Commission addressed this type of issue regarding old meters that were replaced by new advanced meters in Cause No. PUD 201300217. The Commission adopted the ALJ Report including the Joint Stipulations. The Joint Stipulation and Settlement Agreement stated:

> "As existing non-AMI meters are replaced by AMI meters, PSO shall establish a regulatory asset for the unrecovered net book value of non-AMI meters. The non-AMI meter regulatory asset will be amortized using the 9.58% depreciation rate approved for existing meters in this proceeding. The regulatory asset net of accumulated amortization will be included in rate base in future base rate cases"

Thus, in connection with retired meters, the Commission has determined that the utility is entitled to a return of and on the remaining undepreciated book value at the time of retirement.

Regarding SPP expenses, Mr. Hamlett testified that Mr. Chaplin (page 11, line 11 through line 13) reviewed each of PSO's SPP adjustments, but his testimony focuses on Schedule 9 and Schedule 11 (the adjustments Mr. Farrar and Mr. Garrett recommend be removed). Mr. Chaplin states that the Schedule 9 pro-forma amounts comes from the April 1, 2017, published SPP Revenue Requirement and Rates (RRR) file and Oklahoma Transco's 2017 FERC formula rate (page 10, line 11 through line 14). Mr. Chaplin verified that the Oklahoma Transco's 2017 FERC formula rates were shown in the most recently published SPP RRR file dated July 1, 2017 (page 10, line 22 through page 21, line 2). He concludes that PSO's NITS expense is based on actual FERC-approved revenue requirements and rates, which are known and measurable amounts and he has reviewed and verified the amounts (page 11, line 5 through line 8).

Mr. Hamlett further testified that PSO has made this type of pro forma adjustment in past cases utilizing the latest SPP published data, including Cause No. PUD 201500208 which was a fully litigated proceeding.

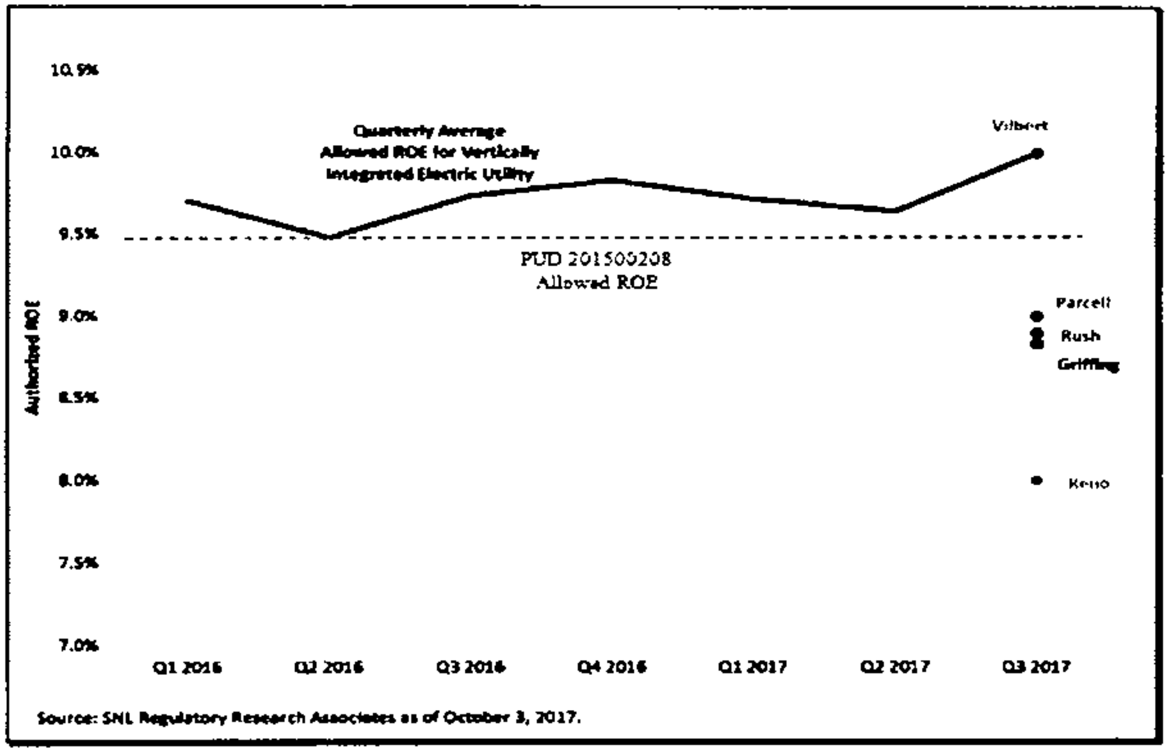
Mr. Hamlett testified that he provided a table that listed each SPP pro-forma adjustment. Supporting that was a summary workpaper. Behind that summary workpaper were two very large spreadsheets that contained significant amounts of data which were provided to all parties in our response to Data Request AG 3-1 (EXHIBIT RWH-3R with electronic spreadsheet). These workpapers were specifically referenced in the response to OIEC 16-3 part b (EXHIBIT RWH-5R). These two spreadsheets were reviewed by Mr. Chapman and referenced in his response to OIEC 1-6. The first spreadsheet contained thirteen separate tabs while the second spreadsheet contains seven separate tabs. Probably the most critical tabs from an on-going basis are the tabs containing RRR or formula rate data that provide certain data from SPP, which again was verifiable from SPP published data as was done by Mr. Chapman. Additional information provided was PSO's load ratio share percentage to allocate the costs to PSO and of course test year amounts needed to calculate the pro forma adjustment. On-going costs less the test year amount equals the pro forma adjustment.

MICHAEL J. VILBERT

In rebuttal Dr. Vilbert produced Figure R-1 which shows the ROE recommendations of the five cost-of-capital witnesses in this proceeding as well as the quarterly average of authorized ROEs for vertically integrated electric utilities since 2016. As clearly shown by

Error! Reference source not found., Dr. Vilbert's ROE recommendation is in line with recently allowed ROEs for vertically integrated utilities while the recommendations of the other witnesses are far below industry norms and run counter to the trend of increasing allowed ROEs. All ROE witnesses agree with the Company's proposed capital structure of 51.5 percent debt / 48.5 percent equity and the proposed cost of debt of 4.60 percent. We differ in our recommended ROE: Mr. Parcell recommends 9.0 percent, Mr. Rush recommends 8.9 percent, Dr. Griffing recommends 8.83 percent, and Ms. Reno recommends 8.0 percent ROE.

Figure R-1: Authorized ROEs since 2016 and Witnesses' Recommended ROE



Dr. Vilbert's main points of rebuttal are as follows:

If adopted, the recommendations of the intervenors would result in PSO having the lowest allowed ROE in the country for an integrated electric utility, but none of the intervenors have provided evidence that the Company's risk is substantially lower than other electric utilities in the country. Moreover, the trend in allowed ROEs is increasing slightly, as shown in **Error! Reference source not found.** above, yet the intervenors' recommendations would be counter to that trend.

The other witnesses have used unreasonably low or inappropriate inputs and approaches that systematically understate the ROE estimates from the DCF and CAPM. Several witnesses have even made substantial errors in their calculations. Correcting for these mistakes and inappropriate inputs would increase the other witnesses' ROE estimates. Specific details are included in Section III.

There are misleading proposals advanced by certain intervenor witnesses on the effect of financial risk on the cost of equity. A company cannot substitute debt for equity financing and expect to lower its cost of capital because companies already have an incentive to reduce their cost of capital. Substituting debt for equity is a strategy that is relatively easy to implement so it is highly unlikely that changes in capital structure would lead to a lower cost of capital. Academic studies of the issue have not supported the view that the cost of capital can be reduced by such a strategy.

If debt were substituted for equity in a company's capital structure, the weighted-average cost of capital would not change, but the required return on equity would increase because of increased financial risk. The cost of equity is a function of both business risk and financial risk. Financial risk cannot be ignored if the cost of equity is to be estimated correctly.

Expecting to finance new investments solely with debt to lower the costs of the project is a common mistake that is identified in nearly all textbooks on corporate finance. In general projects should expect to be financed on average in the same ratio as the Company finances its other assets.

The Company should be authorized full recovery of the remaining balance of its investment in the Northeastern 4 generating plant including the return on the investment. Denying recovery of an investment previously determined to be used and useful by the Commission would increase the risk for not only the Company but also all other regulated companies in Oklahoma. As noted in my direct testimony, compensation for such asymmetric type risks is not provided by an allowed ROE set equal to the estimated cost of capital.

After reviewing the intervenors' testimony in this proceeding, Dr. Vilbert did not change his ROE recommendation for the Company?

He recommended that the Company be allowed an ROE of 10 percent on the equity financed portion of its rate base. This is at the midpoint of the range of 9¾ percent to 10¼ percent that he believed is reasonable for electric utilities of PSO's financial and business risk.

Dr. Vilbert testified that in general, he would characterize the approach of the intervenor witnesses as overly "mechanical" in determining the cost of capital for the Company. With the exception of Dr. Griffing, the intervenor witnesses have performed purely mechanical implementations of their models without apparent consideration for the reasonableness of their results. They have thereby come to the unsupported conclusion that the Company should be allowed the lowest ROE of any recently allowed ROE for vertically-integrated electric utilities in the country.

As stated in several of the intervenor testimonies, the true cost of equity cannot be directly measured. It can only be estimated. The Commission is then faced with the difficult job of determining what an appropriate return on equity for PSO would be based on reliable market information about the risks and returns of comparable companies. An analyst, putting themselves in the place of a hypothetical equity investor, would likely depend on a wide set of estimation models (such as the DCF, CAPM, ECAPM, and Risk Premium) for guidance.

However, the analyst must also consider the reasonableness of these estimation results in order to verify that the models are not being biased by historical or prevailing market conditions. This full evaluation of information is required to come to a reliable estimation of the true cost of equity.

In recommending ROEs below the current rate allowed for PSO and far below recent industry norms, the intervenor witnesses are concluding that the cost of capital is expected to decline in the future and that the Company is significantly less risky than the average electric utility. According to Dr. Vilbert, the intervenors' testimonies provide no support for those conclusions. Analysis of current market conditions suggest an increase in the cost of capital going forward as indicated by forecast increases in interest rates among other things, and the trend in allowed returns around the country is relatively flat with a slight upward trend. Allowed ROEs are certainly not falling dramatically. The mechanical implementation of the models without clear explanation and reasoning of these overall risk factors and market conditions should not be relied on by the Commission in order to determine an appropriate ROE for the Company.

DAVID J. WATHEN

According to Mr. Wathen, Willis Towers Watson's research indicates that annual incentive plan funding mechanisms tied to financial performance are common in the utility industry.

Mr. Wathen testified that while AEP EPS performance determines whether or not the PSO annual incentive compensation plan is funded, it is the performance of PSO as measured against defined operational measures that determines the majority of the incentive award actually paid out to PSO employees. The main driver in determining if PSO employees earn an award is tied primarily to operational measures covering infrastructure development, customer experience and employee experience, which reflect a 90% weighting, while financial performance tied to net income makes up the remaining 10% weighting. The heavy emphasis on operational performance in determining awards earned strongly reflects the importance placed on customer interests. Even if AEP EPS performance funds the annual incentive plan, if PSO employees do not achieve the defined performance goals for the operational measures, they will not earn a significant incentive award.

JOHN O. AARON

Mr. Aaron testified PSO's test year Energy Efficiency/Demand Response (EE/DR) adjustment, a $2.7 million decrease to PSO's filed test year base rate revenue, is like any other proforma adjustment made to normalize the historical test year data so that it reflects known and measurable changes or changes that will occur in the six-month post-test year period. This adjustment, which normalized the kilowatt-hour (kWh) and kilowatt (kW) billing determinants, and resulting base rate revenues, is used to develop the rates to collect the revenue requirement going forward as approved by the Commission. Without the adjustment to the billing determinants, the Company would not have the opportunity to recover its approved revenue requirement because the kWh and kW billing determinants will be overstated resulting in understated kWh and kW per unit charges in PSO tariffs. The EE/DR adjustment reflects 50% of the annualized kWhs from 2016 and 50% of the annualized kWhs from 2017 to arrive at a normalized test year.

According to Mr. Aaron, PUD Witness Ms. Champion recommends a $2.7 million increase to PSO's filed test year base rate revenues which decreases PSO's filed base rate deficiency by the same amount. Her recommendation reverses in its entirety PSO's EE/DR adjustment to base rate revenues for lost net revenues due to customers' participation in PSO's energy efficiency programs. The other intervenors did not address this revenue adjustment proposed by PSO.

Mr. Aaron testified that an adjustment in the base rate case is necessary in order to properly reflect the kWh and kW saved by customers because of their participation in PSO's energy efficiency programs. While the revenues collected under the rider are removed from the base rate revenues reflected in PSO's revenue deficiency calculation, the associated kWh and kW customer savings must be appropriately reflected in the annualized billing determinants in order to calculate rates which will be applied prospectively. All kWh and kW saved by customers would have to occur beginning the first day of the first month of the test year in order to eliminate the need for an adjustment to the historical test year.

Mr. Aaron further testified that all kWh and kW saved by customers would have to occur beginning with the first day of the first month of the test year in order to eliminate the need for an adjustment to the historical test year. The issue is not what occurred through the end of the test year. The issue is the portion of the test year not impacted by the customer's participation and the six-month post-test year period. That participation creates a loss that will then continue every month of every year following the test year. The revenue requirement and resulting rates reflect the test-year adjusted for known and measurable changes and for changes that will occur in the six-month post-test year period. PSO's adjustment for the kWh and kW savings addresses both of these periods and properly reflects the impact in the billing determinants that are used to derive PSO's new base rate tariffs to be used going forward.

According to Mr. Aaron, Ms. Champion also testifies (pages 11-12) that the 2016 Annual Report AND DSM Rider and true-up indicates a $3.3 million revenue reduction associated with a 110 million kWh sales reduction and that supports her recommendation that no adjustment is needed to the actual performance of the PSO programs in the test year. Mr. Aaron did not agree. Mr. Aaron stated that the referenced report and associated DSM rider true-up reflects annualized values for the purpose of calculating the rider and is separate from the base rate revenue calculation in this filing. The DSM rider recovers 2016 lost net revenues that occurred from program participation since the last rate case test year-end. Rates from this proceeding will be applied going forward and are based on the annualized test year revenue requirement and billing determinants. These test year results do not reflect the annualized impact of customer's kWh and kW savings but only the impact from the time of implementation through the end of the test year.

Mr. Aaron also testified that there is no double recovery of lost net revenues from the DSM rider and base rates. The DSM factors that were approved by PUD on September 27, 2017, provide for the recovery of lost net revenues associated with PSO's 2016 programs.

The base rates calculated in this filing to be applied going forward reflect the annualized impact of the programs implemented by PSO's customers.

In response to Ms. Champion's testimony (page 13), Mr. Aaron testified that PSO can agree to remove the adjustment for the annualized kWh and kW savings through June 2017 and the associated revenue if the currently approved DSM rider factors remain in place until the 2017 demand program report and 2017 true-up (and associated factors) are implemented. At that time, the kWh and kW savings through December 2016 will be removed from the calculation of lost net revenues and all kWh and kW savings for 2017 will be included in the lost net revenue calculation. This was the method followed by PSO until the EE/DR pro-forma adjustment was recommended by PUD.

Mr. Aaron further testified that the class allocation factors used in the cost of service study need to be updated to reflect this change to remove the adjustment to kWh and kW for the EE/DR programs.

Mr. Aaron testified that Ms. Champion (page 15) does not recommend an adjustment to update base rate revenues for the six-month post-test year period. Mr. Ed Farrar (page 13) recommends an increase to base rate revenues for the six-month post-test year period. OIEC did not recommend an adjustment to base rate revenues in the six-month post-test year period. All three parties did, however, propose adjustments to rate base and expenses for that period.

According to Mr. Aaron, Ms. Champion describes (page 15) a "mismatch between revenues to be collected and cost allocation" as the basis for her recommendation. Apparently this recommendation is not common across all PUD staff witnesses as there are varying recommendations from other PUD witnesses to update selected rate base and expense components in PSO's cost of service.

Mr. Aaron agreed that a mismatch occurs. In the perfect cost-of-service world, all components of the revenue requirement, cost allocation and rate design would be perfectly aligned and based on the same twelve-month period. With an adjustment to revenues to reflect the changes that have occurred in the six-month post-test year period, at least the financial components can be somewhat aligned. Mr. Aaron stated that all capital and expense components were not adjusted to reflect the six-month post-test year period. The annualized revenues for the twelve-month period ending June 2017 (the six-month post-test year period), including the removal of the adjustment for kWh and kW savings described above, will be provided in the cost of service and rate design rebuttal phase.

Mr. Aaron testified that Mr. Farrar's recommendation (page 12) is based on a "customer count updated to June 30, 2017." He notes discovery responses provided by PSO (in particular AG 14-3 Supplemental Attachment 3) that indicate a $1.4 million increase to the residential class revenue and a $4.8 million decrease to large customers in service levels one through three and claims PSO's revenue update is problematic.

Mr. Aaron further testified that Mr. Farrar used PSO's response to AG 14-3 Supplemental Attachment 2 to make his revenue adjustment for customers in service levels one through three. Mr. Farrar believes PSO's base rate revenue update provided in AG 14-3

Supplemental Attachment 3 is problematic because even though overall customer counts increased between the test year-end of December 31, 2017, and June 30, 2017, PSO showed an overall base rate revenue decrease using customer counts at the June 2017 levels.

Mr. Aaron did not believe that data provided was problematic. Mr. Farrar correctly points out that overall customer counts increased from the test year adjusted levels, a 0.54% increase, although not all rate classes showed an increase. Mr. Farrar fails to mention that kWh sales were down for most classes and overall kWh sales were down approximately 1.4%. The overall base rate revenue reduction based on the change in customer count and kWh sales is slightly lower for the period ending June 2017.

According to Mr. Aaron, it is entirely possible for customer counts to increase slightly and overall kWh sales and base rate revenue to go down, as has occurred here. It is important to look at each rate class individually to see the effect of any change in customer count, which is why PSO provided in AG 14-3 Supplemental Attachment 3 the entire revised Workpaper M-6 with individual rate class detail based on a twelve-month period ending June 2017.

Mr. Aaron also testified that the purpose of AG 14-3 Supplemental Attachment 2 was to support the pro-forma adjustment to retail base rate revenues for the July through December 2016 period that was provided by PSO in response to AG 6-25. Mr. Aaron stated that on page 21 of his direct testimony, PSO made a pro-forma adjustment to the test year revenues is this filing to reflect the base rates, approved in Cause No. PUD 201500208, which began billing the first cycle of January 2017. With the request by Mr. Farrar in AG 6-25 to update retail base rate revenues for the six-month post-test year period, it was necessary to separate PSO's compliance revenue adjustment filed in its original filing from an annual amount into monthly amounts that were summed for the July through December 2016 period. AG 14-3 Supplemental Attachment 2 was not provided as determination of base rate revenues for customers in service levels one through three or as a proof of those revenues which provides the billing units, proposed prices, and the resulting base rate revenues as required in Supplemental Package Workpaper M-4.

PSO does not object to making base rate revenue adjustment that is required by the Commission. What PSO does object to is making a revenue adjustment that does not also include corresponding adjustments to all of the billing determinants associated with a revenue adjustment as is the practice with other pro forma adjustments to revenue.

STEVEN L. FATE

Mr. Steven L. Fate, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO or Company), provided rebuttal testimony.

Mr. Fate summarized key points of the Company's rebuttal testimony by stating:

1. PSO's requested 10.0% return on equity is reasonable because it is based on a variety of factors, including conditions in the capital markets and certain risks faced by PSO. Other parties' recommended returns are lower than those recently awarded by other utility commissions. Some witnesses rely too heavily on a single model, use a

mechanical application of the financial models, others made substantial errors in their calculations, and others utilize assumptions that are not consistent with well-established financial theory.

2. Arguments that Northeastern Unit 4 is not "used and useful" are based on the mis-application of case law and ignore the fact that the Environmental Compliance Plan is a comprehensive set of compliance measures of which each is required to comply with state and federal law. Recovery of and return on Northeastern Unit 4 is consistent with prior Commission practice, is fair to customers and investors, and is common practice around the nation for similar situations.

3. Assertions that there is a general industry trend to write-down generation assets similar to Northeastern Unit 4 is incorrect. Most of the recent asset write-downs have been taken by only a few companies on generation assets that are not owned by vertically integrated cost of service-regulated utility.

4. Other parties recommend a variety of measures intended to reduce the rate increase that results from prudent investments and expenses. These proposed measures should be rejected because they create intergenerational inequity, will increase customers' rates over the long-term and would deny the Company's ability to receive timely cost recovery of reasonably incurred expenses.

5. Contrary to allegations by OIEC and the AG that the Company did not adequately support the reasonableness of Southwest Power Pool (SPP) expenses, Public Utility Division (PUD) witness Jason Chaplin was able to use the substantial data provided by the Company to verify the reasonableness of the expenses. In addition, he verified such data with SPP published information. The Company's pro forma adjustments made to SPP expenses is consistent with SPP adjustments made in prior fully litigated cases that were accepted by the Commission.

6. Ninety percent of PSO's annual incentive compensation is tied to the Company's operational performance in areas other than financial performance including: (1) customer experience, (2) employee experience, and (3) infrastructure development. The plan will not significantly pay out if employees do not perform to target for these areas that cover 90% of the incentive.

7. Due to highly cyclical year-over-year levels of generation non-fuel operation and maintenance (O&M) expense no single year can be considered a "normal" level. The appropriate level of ongoing O&M expense to include in rates is best estimated by using a three-year average expense. The Company's recommended adjustment to test year expenses is reasonable and consistent with the historical average expense.

8. Other parties' proposals for deprecation rates are inconsistent with accepted depreciation practices, misinterpret historical data, and do not apply appropriate judgment in interpreting data.

9. PSO's proposed rate increase has been increased by $1.2 million compared to Direct Testimony due primarily to updating rate base to actual six-months post test year and the acceptance of some proposed adjustments by other parties. PSO has also addressed all of the other parties' proposed adjustments to its recovery of costs in Rebuttal Testimony, and continues to believe the adjusted request for rate relief is reasonable, necessary, and should be granted by the Commission.

Mr. Fate summarized his rebuttal to OIEC witness Garrett as follows:

1. Mr. Garrett states that the Company should not be allowed to recover its investment or earn a return on Northeastern Unit 4 because is it not "used and useful." – I have been advised by counsel that Mr. Garrett's argument relies on incorrect application of case law. His industry examples are materially different than the fact scenario for Northeastern Unit 4 and therefore are not applicable.

2. Mr. Garrett argues that regulatory precedent exists in other states where commissions have denied recovery of the cost of retired coal plants – Each jurisdiction and case has its own set of facts and there are many examples of situations similar to Unit 4 where state utility commissions have approved full recovery of and return on retired coal plants.

3. Mr. Garrett states there is no order, case law or statute where costs associated with an asset that is "voluntarily" retired has been classified as "stranded" and since Unit 4 was "voluntarily" retired, the costs are not "stranded." – The argument of whether an investment falls under a narrowed definition of "stranded" is moot. The question for this Commission is should investors be allowed to recover and earn a return on the undepreciated book value of an asset that served customers for 36 years and then was retired to be in compliance with state and federal law.

4. Mr. Garrett presents a single data point out of the many scenarios and sensitivities under which PSO analyzed its environmental compliance options in an attempt to demonstrate the ECP does not benefit customers – The Company conducted a thorough and robust analysis, considering a multitude of costs and risks and concluded that the ECP is a reasonable alternative given the numerous and necessary difficult long-term assumptions. When fairly considering and balancing all the risks and mitigating factors, the ECP is a reasonable low risk, low cost option. The PUD's and AG's expert witness in Cause No. PUD 201200054, Dr. Craig Roach of Boston Pacific, concluded, "PSO demonstrated the prudence of its choice of the EPA Settlement through its extensive evaluation of the alternatives in Cause 54." Moreover, Mr. Garrett's arguments are moot given that the Commission found the plan prudent and that reasonable costs associated with the plan should be recoverable.

5. Mr. Garrett believes that customers should not have to bear the cost of Unit 4 since the Company made a decision that was not least cost for customers and the decision was made so that benefits could inure to the Company – There is no evidence that the decision inured to the benefit of the Company. Rather there is substantial evidence the Company lost significant earnings opportunity by avoiding the investment necessary to install scrubbers on both Northeastern coal units.

6. Mr. Garrett contends that the Commission has several options for partial cost recovery such as used in the Black Fox nuclear plant order and the OG&E Arbuckle plant – The examples discussed by Mr. Garrett are factually very different than Northeastern Unit 4. In the case of Black Fox the unit never reached operation unlike Northeastern Unit 4 which served customers for 36 years. In the case of the OG&E Arbuckle plant it was mothballed, placed in the FERC account for Electric Plant Held for Future Use, rather than retired like Northeastern Unit 4.

7. Mr. Garrett argues that the Commission was wrong when it set the original depreciation rates for Northeastern Units 3 & 4 and that the Commission's decision in 2006 to change their usefully lives to 60 years is indelibly correct – The estimated useful life of an asset must frequently be reassessed when circumstances change. In the case of Unit 4, the useful life was ultimately determined by environmental compliance requirements and not an estimate made back in 2006 before the full impact of Regional Haze Rule (RHR) and the Mercury and Air Toxics Standard (MATS) was known.

Mr. Fate summarized his rebuttal to AG witness Mr. Bohrmann by stating that:

1. Mr. Bohrmann states that the Commission's prior approval of the Company's Environmental Compliance Plan intentionally left the issue of Unit 4 cost recovery open for future review – Regardless of Mr. Bohrmann's characterization of the Commission's intent in their order in the 2015 Rate Case, PSO's argument is about consistency – that to not allow the full recovery of and return on Unit 4 would be fundamentally inconsistent with the Commission's prior findings in Cause No. PUD 201500208 where they approved cost recovery for the NOx controls and Oklaunion, and where they found the ECP prudent.

2. Mr. Bohrmann argues that the Commission's original ruling in 1981 that Unit 4 was "used and useful" is not relevant on a going-forward basis – Up until 2006 the Commission's authorized deprecation rate for Unit 4 was based on it remaining in service for 31 years. The Commission decided in 2006 to extend the depreciable life to 2040 when 31 years has now proven to be closer to the actual life of the unit. It would now be inappropriate for the Commission to deny full recovery of the investment.

3. Mr. Bohrmann believes the Company voluntarily retired Unit 4 resulting in the unit no longer being used and useful once it retired – The Company did not voluntarily retire Unit 4. It was part of an overall plan to bring PSO's generating fleet into compliance with RHR and MATS. But for these federal environmental laws PSO would not have been required to implement any of the compliance measures. Mr. Bohrmann even admits that Northeastern Unit 3 could not be operating if Unit 4 remained in service. Thus, in that sense, Unit 4's retirement is necessary to keep Unit 3 running and is therefore used and useful and serving customers.

4. Mr. Bohrmann suggests it is necessary to incent the Company to maximize the use of retired Unit 4 the Company should be allowed to earn a return on only components in common with Unit 3 or where salvaged and used elsewhere in PSO's generating fleet – The so-called incentive is not effective. The proposal to allow materials and equipment from Unit 4 in rate base to the extent they are used elsewhere to serve PSO customers is nothing more than what PSO would receive under normal cost recovery.

Mr. Fate did not agree with Attorney General witnesses Edwin C. Farrar and James B. Alexander who made recommendations based specifically on the goal of reducing the impact to current customers.

Mr. Fate testified that: first, for reasons similar to what he made in his direct testimony related to reasonable depreciation rates, it is unfair to future customers to pay for service provided to current customers. Deferring current expenses to future customers completely ignores the fundamental ratemaking concepts of intergenerational equity and cost causation. To a significant degree, the size of the requested increase in this case is a result of prior actions that have resulted in deferral of reasonable cost recovery to serve current customers. To further defer current expenses on the back of future customers will increase overall cost to customers and compound the increase experienced by future customers who will be required to pay for not only the services they receive but for services rendered to prior customers. Continued deferral of reasonably incurred expenses also creates cash flow difficulties for the Company and makes it more difficult to fund the necessary investments the Company needs to make to continue the high level of service our customers currently enjoy.

According to Mr. Fate, Mr. Farrar argues that current costs to serve customers should be deferred because customers in the future will have greater financial wherewithal to pay for the increase due to wage growth. Mr. Farrar also claims that the Company can change its capital structure by financing large projects with debt only, and thereby lowering the Company's overall cost of capital and reducing rates. Finally, he makes the suggestion that the Commission can simply ignore the Company's requested increase by implementing a phase in over three years.

Mr. Fate testified that deferring cost recovery to future customers would be inappropriate. Moreover, the notion that customers can afford to pay more for the electrical service in the future because of wage growth ignores the fact that (1) all else being equal the cost to serve customers will also be increasing at a similar inflation rate, and (2) generally it is more costly to customers over the long run when recoverable costs are deferred.

Mr. Fate testified that Mr. Farrar's suggestion that the Company can finance new projects with only debt, thereby reducing its cost of capital is a false claim. In effect, Mr. Farrar is suggesting the company increase its debt leverage under a false pretense that the investment community will ignore the increased financial risk. To the contrary, investors will not ignore the increased financial risk represented in the increased debt leverage of the Company and will impute an increase risk to the Company's capital.

Finally, while the simplistic notion that the Commission should phase in over several years the requested rate increase ignores the Company's need to recover reasonable expenses in a timely manner and the financial harm that would result if it is not allowed to do so. If the Company were to be kept financially indifferent to such a phase in plan, customers' rates would be higher in the long term than if the Commission grants PSO the relief requested in this cause.

Mr. Fate testified that Mr. Alexander states that the requested increase in storm expense in base rates be denied "given the magnitude of the rate increase requested in this case."

According to Mr. Fate, the amount in base rates has not been adjusted since the $2.8 million in base rates was set back in 2008. It clearly needs to be reset based on more current levels of storm damage costs and can be reviewed again in the future if average costs change.

Mr. Fate did not agree with OIEC witness Garrett and AG Witness Farrar characterization of the Company's support for SPP expenses as inadequate. PSO fully supported the reasonableness of the SPP expenses. Contrary to the accounts of Mr. Farrar and Mr. Garrett, three PSO witnesses (Mr. Hamlett, Mr. Ross and Mr. Smith) provided support for the SPP charges in direct testimony.

According to Mr. Fate, as Mr. Hamlett discusses in his rebuttal, in addition to providing narrative and a table detailing each SPP pro-forma adjustment in his direct testimony, he also submitted multiple workpapers thoroughly supporting the charges. While both Garrett and Farrar discuss the testimony of Mr. Hamlett to a degree, they do not acknowledge the vast amount of data provided in the workpapers and supporting documentation.

It is common practice in a rate case to support adjustments with narrative and to then supply more detailed support through workpapers and schedules. This is an accepted approach, because often, as is the case here, workpapers are voluminous spreadsheets and including them in filed testimony is often impractical.

PUD Witness Jason Chaplin's responsive testimony illustrates this common practice. In his testimony he details the process that he used and the information he reviewed to verify the reasonableness of the SPP charges, including his review of the aforementioned workpapers.

Mr. Fate further testified that although both Mr. Garrett and Mr. Farrar make no mention of Mr. Smith's testimony, it provides substantial support for the test year adjustment by describing the expenses contained within Account 565 and detailing the projects booked there. (Account 565 makes up the majority of the test year increase.) More specifically, beginning on page 21, he details the twelve largest projects and explains why they were completed. Beginning on page 25, Mr. Smith also discusses the transmission planning services provided by SPP and the benefits that the transmission system expansion brings to customers.

Mr. Fate testified that Mr. Garrett states on page 64 of his responsive testimony that Mr. Ross's testimony "does not support the specific test year adjustments to SPP expenses… ." While it is true that Mr. Ross's direct testimony does not mathematically support the SPP pro forma, it does provide critical support related to the reasonableness of the expenses. However, Mr. Garrett dismisses this support, and in doing so, appears to miss the main point of Mr. Ross's testimony. In the purpose section on page three of Mr. Ross's testimony he states, "I will discuss how PSO, through representation by AEP and PSO staff, actively participates in the SPP stakeholder groups, which provide oversight to the SPP transmission planning and other activities so that the projects constructed and activities performed by SPP are done in a manner that is reasonable and beneficial." The details of PSO's participation in the stakeholder groups are key in supporting the reasonableness of the SPP costs because stakeholder groups exist to provide additional oversight of the SPP process to "ensure PSO (and its customers) pay the lowest reasonable costs for the services it procures from the SPP." Mr. Garrett also ignores Section VI. of Mr. Ross's testimony entitled "Reasonable Costs and Benefits to PSO Customers" where Mr. Ross details the steps taken to ensure that the costs paid by PSO customers are reasonable.

Mr. Fate further testified that in addition to attacking the reasonableness of the SPP test year adjustment, Mr. Garrett also claims that PSO failed to comply with the requirements of the Southwest Power Pool Transmission Cost Tariff (SPPTC) and should therefore be required to refund the $42.88 million of charges collected through the SPPTC during the test year.

According to Mr. Fate, Mr. Garrett's claim is without merit. Please refer to the testimony of PUD Witness Mr. Chaplin for a description of the substantial information supporting the charges collected through the SPPTC which was made available to all parties in this cause. Note that the SPPTC requirement to support the reasonableness of the charges collected during the test year in a rate case is the same information provided to PUD each year during the annual SPPTC factor true-up. Consequently, before PSO changes the annual SPPTC factor, a thorough filing package is submitted to PUD prior to approval and implementation of that factor. The same contents of that filing package (for the test year) were provided to parties in this cause.

ANDREW R. CARLIN

Mr. Carlin submitted rebuttal testimony. He responded to AG Witness Farrar, OIEC Witness M. Garrett. According to Mr. Carlin, their arguments ignore that PSO's operating performance is the primary factor in determining PSO incentive compensation, which despite the earnings multiplier would not be paid if PSO did not meet the operational goals directly benefitting customers. Their arguments also ignore the fundamental purpose of the Company's incentive compensation, which is to provide market competitive compensation which enables the Company to attract, motivate, engage and retain the suitably experienced and skilled employees needed to efficiently and effectively provide its service to customers. The Company's incentive compensation provides these substantial benefits to customers.

Mr. Carlin testified that no party to this case disputes that the total compensation the Company provides to its employees is market competitive, reasonable and fair. In fact, witness Rush states that:

> If incentive plans were eliminated, and those dollars were inserted as base salary instead, compensation would still be in a range that is competitive with compensation packages provided by other like-sized companies.

Further, no party disputes the need for the Company to provide market competitive compensation in order to attract and retain a suitably skilled and experienced workforce and thereby efficiently and effectively provide quality electric service to customers. It is inappropriate to disallow the expense of incentive compensation that is undisputedly both reasonable and necessary for the provision of electrical service to customers and therefore, highly beneficial to customers, particularly when the benefits associated with such incentive compensation have and will continue to inure to customers.

Mr. Carlin testified that the Commission should consider that more recent rulings for gas utilities provided full recovery of incentive compensation. While the gas utilities subject to the orders approving full recovery of annual and long-term incentive compensation each have performance-based rate mechanisms, PSO's compensation practices are not materially different and align with customer interests for the same reasons cited in these Commission orders.

Mr. Carlin also testified that the change in the PUD's recommended treatment of incentive compensation is also notable. PUD now recommends inclusion of 100% of short-term incentives and 25% of long-term incentives because "PUD believes that it is prudent for the Company to have a comprehensive incentive plan, including both short-term and long-term incentives, as an important part of employee attraction and retention." PUD understands that "If incentive plans were eliminated, and those dollars were inserted as base salary instead, compensation would still be in a range that is competitive with compensation packages provided by other like-sized companies. As such, a portion of the expense for incentive compensation should be recovered from consumers. PUD recommends that the Commission should allow 100% of Short-Term Incentive Compensation in the amount of $12,488,266.48, and allow 25% of Long-Term Incentive Compensation in the amount of $1,086,491"

Mr. Carlin testified that the Company's annual incentive program provides substantial benefits to customers at no incremental cost above the cost of providing market-competitive compensation through base pay alone. None of the performance measures therein have been shown to be detrimental to customer interests on the whole. Furthermore, no party has challenged the Company's compensation levels relative to market or the critical role that incentive compensation plays in maintaining the competitiveness of these levels. As such, 100 percent of the Company's incentive compensation expense is a just, reasonable and necessary cost for the efficient and effective delivery of the electric service to its customers. Therefore, the Company requests that 100 percent of the target level of annual incentive compensation be included in the Company's cost of service, which is the level required for the provision of market-competitive compensation. The Company is reasonably and fairly requesting to include only the target level in rates and for the Company and its stockholders to assume 100% of the financial risk and expense associated with above target performance.

Mr. Carlin testified that Witness M. Garrett proposes to remove 50 percent of the Company's short-term incentive compensation and 100 percent of the Companies' long-term incentive compensation from rate base because he argues that the treatment of capitalized incentive compensation should be consistent with the treatment of incentive compensation in the Company's cost of service for rate making purposes. The impact of this proposal, if adopted, would be to immediately eliminate the Company's ability to earn a fair return on the reasonable and prudent capital invested in its assets.

TOMMY J. SLATER

Mr. Slater filed rebuttal testimony to AG witness Farrar and OIEC witness Mark Garrett.

Both witnesses proposed removal of PSO's adjustment to normalize test year levels of generation O&M expense.

According to Mr. Slater no single year is "normal." In addition to major planned maintenance being cyclical, there is planned activity that occurs over time and unplanned activity that can occur at any time. All of these types of activities affect O&M expense differently year to year. Based on the Company's extensive operating experience, he believed the three-year average captures more of the cyclical and unplanned maintenance activities than any single test year can. Mr. Garrett alludes to things that might have impacted O&M but provides no evidence of any abnormal activity that contradicts the Company's long-standing assertion that generation O&M fluctuates year to year and that a three-year average fairly approximates an ongoing level of expenses for operating and maintaining PSO's generating fleet. Non-recurring activity that did impact O&M is accounted for by removing Northeastern Unit 4 O&M before averaging.

Mr. Slater testified that Mr. Farrar asserts that the adjusted O&M expenses for 2014-2016 indicate a trend of declining O&M expense, rather than a fluctuation. According to Mr. Slater, the decline from 2014 through 2016 in adjusted Generation O&M expenses reflects the progressive elimination of preventive maintenance on Northeastern Unit 4 leading up to its retirement in 2016. This means that progressively less O&M money was spent on the unit each year which is why the total O&M expense in those years did decline. However, that decline ended with the retirement of Northeastern Unit 4 in 2016 and will not continue to decline going forward. So while the three-year period 2014-2016 O&M levels decreased due to a reduction in maintenance on Northeastern Unit 4, they still include the regular fluctuations in maintenance for the other PSO units.

Mr. Slater further testified that major maintenance that impacts expenses includes recurrent scheduled activities, generally foreseen one-time or infrequent occurrences, and unforeseen events. A turbine overhaul, a significant O&M expense when it occurs, is scheduled on approximately a 10-year cycle. Depending on the number of units undergoing a turbine overhaul in a given year O&M expense can vary greatly from a year – such as the test year – in which there were no turbine overhauls. Finally, aging plants can require maintenance that spikes an annual expense. Mr. Slater testified that PUD witness David Melvin summed it up best in his responsive testimony: "PUD agrees that Generation O&M activities are not consistent from year to year and older equipment will have increased expenditures for maintenance in future years." (Responsive Testimony of David Melvin at p. 13, line 16).

Mr. Slater did not agree with Mr. Garrett's characterization of the proposed adjustment for maintenance of the environmental controls.

The $300,000 is a new ongoing expense due to the addition of the environmental controls that went in service in 2016, not an increasing existing cost as Mr. Garrett claims. The amount was determined by the Plant Managers after assessing the operation and staffing needs that the new equipment will require. The controls installed at Comanche replaced older similar equipment and thus present no new ongoing maintenance costs. The Dry Sorbent Injection (DSI) and the Activated Carbon Injection (ACI) with fabric filter are new systems installed at Northeastern Unit 3 with new maintenance requirements for their efficient ongoing operation.

Mr. Slater testified that Mr. Garrett was not correct because the reduction proposed in O&M expense for the retirement of Northeastern Unit 4 is not a percentage reduction but rather a removal of non-recurring actual expenses from the test year. Of the $78,871,294 actual test year Generation O&M expense, $293,664 were related to NE4 during the first quarter of the test year before it was retired, and thus should be removed from the test year O&M going forward. Further, the Company is not intending to imply that the $293,000 represents the total reduction in O&M due to the retirement of Northeastern Unit 4. Maintenance on the unit was progressively reduced over a period of several years prior to its retirement.

Mr. Slater testified that Mr. Garrett's comparison of the test year O&M to the historical combined O&M of Northeastern Units 3 and 4 was flawed.

Mr. Garrett does not reference the source of the unit-specific cost data or the Northeastern Unit 3 estimated percentages presented in his Table 3 and Exhibit MG-3. Mr. Garrett's recommended adjustment relies on this unit-specific cost data which was neither provided in Mr. Slater's direct testimony or responses to data requests, nor referenced in his responsive testimony. According to Mr. Slater, Mr. Garrett assigns arbitrary allocations intended to represent expenses for Northeastern Unit 3 that vary for each FERC account. These arbitrary allocations are wrong and result in calculations that do not provide an accurate comparison of O&M costs related to Northeastern Units 3 & 4. Mr. Garrett uses the average of 2013-2015 costs to represent the "average historical level of expense." (Mark E. Garrett at p. 57, line 12) This is misleading because the years 2013-2015 do not represent historical levels of O&M for Northeaster Units 3 & 4 but rather years of declining O&M. A more appropriate comparison would be to compare the test year O&M to expenses in 2012 (as taken from the FERC Form 1 report), which was the year before the O&M reductions began for Unit 4. This comparison of Northeastern Units 3&4 production expenses was provided in the Company's response to data request OIEC 14-13 (Exhibit TJS-R-1):

"…25.8 million in 2012 and 22.6 million in 2016. This represents a $4.2 million reduction."

Mr. Slater further testified that as further explained in the response to OIEC 14-13, the cost reductions related to Unit 4 are greater than $4.2 million when staff reductions from Unit 4 are considered. However, because many of those staff were reassigned to manage the new environmental controls at Unit 3, the net impact to O&M due to staffing has been minimal.

JOHN D. QUACKENBUSH

John D. Quackenbush submitted rebuttal testimony on behalf of PSO.

Mr. Quackenbush has 35 years of experience working in the field of utility regulation. His career includes: more than four years supporting state utility regulators as a finance staff member of the Illinois Commerce Commission; 14 years performing regulatory and treasury functions in the telecommunications industry for Sprint Corporation, partially during the application of utility cost of service regulation to incumbent local exchange carriers and partially during the transition from cost of service regulation to price cap regulation; 11 years in the investment community covering approximately 80 North American companies including regulated utilities, building U.S. and Canadian domestic portfolios, and leading the global utilities team in building global utility portfolios for UBS Global Asset Management (UBS); more than four years regulating utilities as a state utility regulatory commissioner as Chairman of the Michigan Public Service Commission; and most recently, for the last year, providing consulting services to participants in regulated utility industries.

Mr. Quackenbush testified that fairness and sound regulatory policy requires a balancing of investor and customer interests. This balancing requires careful consideration of the effect of rates on customers and on legitimate investor expectations of a return on prudent investments. These two witnesses summarily dismiss the beneficial service customers received from NE4 for 36 years in recommending that investors be deprived of the return on the prudent investment that they made in this unit that provided so many years of reliable service. The recommendations of these two witnesses do not reflect a proper striking of a reasonable balance between these interests. Case law, and my experience, teaches that fairness and justice is not achieved by rigid application of mechanical principles, but instead by a reasoned review of the facts and circumstances judged by the fairness of the end result. The review should consider established regulatory principles, but not to the exclusion of consideration of the impact not just on customers but necessarily on the financial impact to the company. Both of these witnesses give no consideration to investors, and this does not serve this Commission or utility customers in the long run, nor does it equate to sound regulatory policy. Additionally, prudent regulatory policy takes into consideration whether the regulatory signals sent by certain actions promote desired utility behaviors or instead provide perverse incentives contrary to customers' and the broader public interest.

In response to Witness Bohrmann's statement that his proposed disallowance is "economic reality as it currently exists" and therefore will not send a perverse signal regarding investment decisisions (at p. 16), Mr. Quackenbush testified that he did not agree.

As Company Witness Fate explains, the "economic reality" that Mr. Bohrmann describes is not reality at all; and to dismiss the potential implications of this Commission issuing an order resulting in a write off of an asset such as NE4 shows a lack of understanding on Mr. Bohrmann's part. Investors generally strive to be aware of downside risk of their investments as a matter of course. Mr. Bohrmann appears to believe that if investors know about the worst case outcome, then the right thing for the Commission to do is to give the worst outcome to investors. He casually dismisses any hint of fairness from his recommendation.

Different Commissions and different utilities confront the challenges they face in a myriad of ways, but as a former commissioner, ultimately my decisions rested on the circumstances and the facts on the record in front of me, and the regulatory policy and signals I wanted to send to the utilities I regulated. My observation is that utilities generally are extraordinarily good at following regulatory incentives as well as disincentives. The adoption of Mr. Bohrmann's recommendation would send a perverse signal to both investors and the utility according to Mr. Quackenbush.

To comply with environmental requirements, the Company had a variety of options. Selecting the increased investment option would have allowed the Company to avoid the immediate situation where Mr. Bohrmann recommends a perverse outcome and to instead significantly increase PSO's earnings on rate base and long run costs to customers. Disallowing recovery of NE4 will essentially punish PSO for pursuing an option that was more beneficial to its customers than to its shareholders. To ignore the signal that this sends regarding future investment decisions is to ignore reality. The reality is that utilities in evaluating future resource decisions may be forced to forgo the best options for customers to avoid a potential cost disallowance of the undepreciated remaining book value of an asset, and instead spend capital to extend the life of the asset(s) as long as possible – regardless of the cost and risk to customers.

Mr. Quackenbush testified that while serving on the Michigan Public Commission he dealt with a similar situation. In 2014, my colleagues and I issued an order approving a settlement that allowed Indiana Michigan Power Company (I&M) to recover the remaining book value of its Tanners Creek coal plant (Case No. U-17524). Due to environmental regulations, I&M was faced with making significant investments to prolong their lives or to refuel with a fuel other than coal, or to close the units. Ultimately, I&M chose to retire Tanners Creek by June 1, 2015, which was prior to the end of its then depreciable service life.

The settlement agreed to by all parties, including a group representing industrial intervenors, allowed for recovery of prudent investment included in rate base by extending the period over which costs would be recovered.

Even through a settlement, Mr. Quackenbush testified that he Commission still had to determine whether or not the settlement was in the public interest and whether or not it struck the appropriate balance between customer and shareholder interests.

THOMAS J. MEEHAN

Mr. Thomas J. Meehan, filed rebuttal testimony in support of PSO.

Mr. Meehan testified that his initial overall observation was that none of the witnesses [Weber, Dunkel and D. Garrett] present any independent studies or alternative sources of the costs that are expected to be incurred to dismantle and remove PSO's generating facilities upon their retirement. Each witness simply criticizes certain aspects of the demolition studies, without offering alternative engineering studies or sources of cost covering the complete costs of demolition of each of PSO's generating units based on consideration of the specific attributes of each facility.

According to Mr. Meehan, the S&L Conceptual Demolition Cost Estimate Report that he sponsored in his Direct Testimony is an actual analysis of the costs that are expected to be incurred to dismantle and remove each PSO generating plant after its retirement. The studies were conducted using the extensive power engineering and generation facility experience of S&L and represent a reasonable, appropriate, and reliable projection of the costs of dismantling and removing PSO's generating facilities upon their retirement.

Mr. Meehan further testified that the S&L demolition cost estimates are based on the assumption that the facility will be completely dismantled with the most efficient methods that open up the basement areas of these facilities and deposit demolition rubble in these areas.

Due to the inherent differences between each unique generating facility, each plant was evaluated on an individual basis to ensure that prudent and reasonable cost estimates were provided for the most-likely demolition scenario. Site-specific walk-downs with PSO staff and drawing reviews were performed to clearly define the scope of demolition, excavation, and disposal necessary for each individual site. S&L used discussions with site staff, documents, and the dimensional information from drawings to calculate the extent of excavation and disposal required.

Contrary to Mr. Garrett's assertion, the S&L demolition cost estimate studies are based on likely decommissioning contracting approaches as well as realistic demolition techniques for the dismantlement and scrapping of PSO facilities.

In response to PUD Witness Weber, Mr. Meehan testified that the "changes in methodology" that Ms. Weber references throughout her Responsive Testimony are what he considered changes to inputs, such as the third-party sources relied upon for regional labor rates, that contribute to differences between cost estimates, but certainly are not a change in the overall methodology or approach to the demolition cost estimates. Most often, these input changes are implemented to improve cost estimating and to create a more robust and accurate estimate.

The PAS (utilized in prior demolition cost estimates) and RS Means (utilized in the 2017-cost estimate) are both valid and acceptable industry publications and sources for labor wage rates. RS Means is available earlier in a given year, allowing the wage rates included in the demolition cost studies to be more representative and commensurate to the timing of the estimates.

Mr. Meehan further testified that the Public Utility Commission of Texas (PUCT) found S&L's estimates reasonable for Southwestern Electric Power Company (SWEPCO) in its Final Order dated October 10, 2013 in Docket No. 40443, found in its Finding of Fact Number 193 that:

> "*The plant demolition studies SWEPCO used to develop terminal removal cost salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment.*"

Contrary to PUD Witness Weber, Mr. Meehan testified that contractor G&A and profits are a legitimate line item to be included in a cost estimate. These are expenses that would be incurred in the overall cost on any contract project.

Mr. Meehan disagreed with Ms. Weber's allegations that S&L did not provide adequate information. Several pieces of documentation requested by Ms. Weber are either subject to contractual restrictions on dissemination by S&L or involved proprietary S&L procedures. Nonetheless, to make such information available for Ms. Weber, PSO purchased copies of the RS Means and PAS books, and S&L provided a sample calculation of proprietary methods for crew rates included in the study. This information was made available for Ms. Weber at PSO's Oklahoma City Office almost two weeks prior to the filing of responsive testimony. As such, Ms. Weber's allegation that there was a lack of documentation or information provided is unfounded. Further, S&L provided assumptions and specific details in the body of the demolition cost estimates in Exhibit TJM-3 of Mr. Meehan's Direct Testimony at a level of detail sufficient for review by experienced and knowledgeable power plant engineers.

Mr. Meehan further testified that contrary to Ms. Weber's allegation, the environmental upgrades for Northeastern Unit 3 had been already included in the 2015 demolition cost estimate. This fact was referenced in the 2017 cost estimate. Ms. Weber's concern regarding the Northeastern Unit 3 upgrades and scrap metal tonnage is moot, as one would expect the scrap metal tonnage in the 2015 and 2017 cost estimates to be similar since the upgrades were included in both estimates.

Contrary to Mr. Dunkel's testimony, Mr. Meehan testified that it is not uncommon for engineering companies such as S&L not to provide demolition services.

Mr. Meehan did not agree with OIEC, PUD, and the OAG that it would be proper to exclude an allowance for contingency from the power plant demolition studies. All three witnesses use the arguments I rebutted earlier to state that the demolition cost estimates are "likely high" to validate the removal of legitimate contingency factors. Cost estimates for virtually all contract work in all industries across the country typically include some level of contingency. It would be unreasonable and unrealistic to exclude contingency as it is an industry standard.

Mr. Meehan testified that both Ms. Weber and Mr. Dunkel recommended adjustments by using monthly averages with different periods for scrap prices from American Recycler, the source relied on in S&L's prior demolition cost estimates. Ms. Weber and Mr. Dunkel then removed 10% for separating and transport of materials.

According to Mr. Meehan, Ms. Weber and Mr. Dunkel are essentially recommending that scrap values are calculated using a method that is less accurate than the one used by S&L in the 2017 estimates.

It was determined that utilizing localized pricing closer to PSO's generating stations that was inclusive of handling and transport would be the most accurate method to determine cost at the point in time. Prior to the 2017 cost estimate, S&L utilized the regional, multi-state price from American Recycler and subtracted 10% from the price to account for the handling and transport. S&L contends that it is reasonable and more accurate to obtain a price inclusive of these elements closer to PSO's facilities.

Contrary to Mr. D. Garrett's concern, the assumption that all assets removed at the time of demolition are scrap value only, and not subject to resale, is appropriate considering the typical approach for the life cycle operation of a power plant facility. As a power plant ages, it will require an increasing amount of O&M expense to maintain the plant in a safe and reliable manner. As the economics of operating the generator degrade, the operator will often be required to find opportunities to save in some areas while attempting to maximize the economics of the generating plant. By the time the plant is uneconomic and reaches the end of its useful life, the general condition of the plant has often degraded to a point where there is little usable equipment. As such, end of life plant equipment has very little resale value other than scrap because it is very rarely in acceptable condition, does not have warranty or performance guarantees that new equipment would have, and is typically inefficient and obsolete relative to other equipment available in the market. Mr. Garrett also ignores the costs with proper removal, transport, installation, reconnection, and commissioning of used equipment that decreases any potential embedded value.

In response to Ms. Weber and Mr. Dunkel, Mr. Meehan testified that it was his understanding that the scope of the Breed demolition conducted to date by AEP only constituted a portion of the full scope of demolition that is detailed in the 2005 S&L cost estimate for the Breed facility. Considering that the full scope of demolition costs detailed in the S&L study are necessary to remove all of the components associated with the plant's prior operations and to restore the site, to the extent practical, to its original condition and that only a partial demolition was completed, confirms the validity of the S&L's approach, and not the point of Ms. Weber and Mr. Dunkel that S&L's approach are overestimated.

According to Mr. Meehan, Mr. Dunkel made similar arguments and comparisons to I&M's Breed Plant as he does in this proceeding. The IURC stated the following in its Order dated February 13, 2012:

> *"We find that it is not appropriate to use the actual cost data from the Breed Plant demolition to estimate costs for demolition of distinct facilities with unique configurations. Accordingly, we further find that Mr. Dunkel's proposal to adjust the Tanners Creek and Rockport demolition cost estimates based on cost data for the Breed Plant demolition must be rejected."*

Although Mr. Dunkel makes no specific adjustment to PSO's demolition cost estimates in consideration of Breed, he does attempt to characterize the PSO's demolition cost estimates as excessively high, as does Ms. Weber, a point that the IURC rejected.

> *"The evidence of record shows that S&L is well-qualified with specific expertise introducing demolition cost estimate studies and that the S&L demolition cost estimates are clearly substantiated and based on site specific data, assumptions consistent with prudent industry practices and previous S&L demolition estimates. This Commission has long accepted and relied on site specific S&L demolition cost studies for purposes of establishing depreciation rates."*

STEVEN F. BAKER

In Rebuttal testimony to AG Witness Alexander, Mr. Baker testified that while PSO has invested in system hardening and resiliency programs for its distribution system, Mr. Alexander mischaracterizes the amount of that investment. Mr. Alexander states that "PSO has made significant infrastructure upgrades in its distribution ($205 million)..." system. (at 6) However, of the $205 million in distribution investments, only $24.8 million of this amount was for system hardening and resiliency programs. Much of the distribution investment since the last rate case has been for routine items, such as street/highway locations, third party requests, distribution line meter and transformer purchases, new service to customers, and service restoration. Although these investments are extremely important in maintaining PSO's distribution system, they do not harden the system or improve resiliency, and would therefore not help minimize storm damage.

Mr. Baker further testified that in terms of the system hardening and resiliency programs, PSO was only approved to expand its Reliability Vegetation/Underground (RVU) Rider to include system hardening and resiliency programs on December 18, 2013, in Cause No. PUD 201300202. The RVU Rider, which became the System Reliability Rider (SRR), helped PSO to invest the aforementioned $24.8 million in system hardening and resiliency programs over the past couple of years. However, the SRR was terminated effective as of the end of 2016 per the final order in Cause No. PUD 201500208. While the vegetation management portion of the rider was moved to bases rates, there was no similar provision for the hardening and resiliency funding.

Also as part of this assertion, Mr. Alexander states that AMI helps lower costs associated with damage restoration. In this assertion Mr. Alexander is correct, as I describe the benefits of AMI during storms in my direct testimony. However, the amount of storm cost that AMI will be able to reduce will vary from storm to storm. Mr. Baker further testified that as he had stated in direct testimony, even with AMI in place, the July 2016 windstorm still cost approximately $4.9 million. Even fully utilizing AMI's capabilities, this one storm was nearly $2.0 million more than what PSO currently has in base rates for storm expenses.

Additionally, Mr. Alexander argues that PSO's vegetation management program "...decreases damage to the system and lowers costs in the long run." (at 6-7) Mr. Alexander is correct to a certain extent, as PSO's vegetation management program has helped to limit storm damage. However, Mr. Alexander fails to take into consideration that PSO's current cycle-based vegetation management program has been in place since 2005, with PSO's first four-year cycle being completed in 2010. Although PSO's vegetation management program has significantly benefitted the system, PSO still experienced average storm costs of approximately $10.7 million per year for the period of 2010 through 2016 while the current vegetation management program was in place. Stated another way, PSO's vegetation management program has already achieved significant benefits and will continue to help maintain PSO's reliability, but it will do little to improve storm cost reduction beyond what has already been realized.

According to Mr. Baker now is the appropriate time to update PSO's storm damage expenses to reflect a more current average. As Vice President of Distribution Operations for PSO Mr. Baker testified it was his responsibility to ensure the reliability of PSO's distribution system for the benefit of PSO's customers. As part of that responsibility, both Company witness Hamlett and I have established the need to update storm expenses by showing the historical cost of storms PSO has experienced, describing the severity of these storms in detail, as well as PSO's processes, programs, and efforts to minimize these costs.

Mr. Baker supported the conclusions of Mr. Spanos that wood pole failures increased with age. According to Mr. Baker, over the course of his 27 plus year career in distribution operations, he has consistently observed that wood pole failure rates increase with age. Wood poles have a finite life and are constantly under attack by natural forces such as wind, ice, rain, excessive temperatures, lightning, bacteria and exposure to sunlight. As a result, wood poles are always in some state of decay and deterioration.

PSO's current ground line inspection programs support the fact that failure rates increase as wood poles age. A sample of recent ground-line inspection results indicates the wood pole failure rate increases steadily with each 10 year band from year 11 through year 60 in service. This sample shows that 50+ and 60+ year old poles fail at nearly twice the rate as 40 year old poles. This information matched Mr. Baker's observations and cumulative experience regarding wood pole performance and failure rates.

PAULINE M. AHERN

In response to Witness M. Garrett's "thought" that the OCC should not give Ms. Ahern's testimony any weight, Ms. Ahern testified that had she testified in approximately 275 rate cases over the last 30 years, before more than 30 regulatory commissions on various topics, not limited to rate of return, e.g. capital structure issues, relative investment risk issues, and credit quality issues, all of which does indeed qualify me as a ratemaking expert. In addition, as my direct testimony discusses, the revenue requirement set in any rate proceeding, including this one, is a combined function of O&M expenses, depreciation, income taxes, rate base and the capital (debt and equity) financing that rate base. Therefore, the level of each one of these components is critical to and interrelated with the development of fair and reasonable rates, including the fair rate of return and she is therefore imminently qualified to comment on the effect of regulatory policy on the cost of capital, including the investor required return on common equity.

According to Ms. Ahern, Witness D. Garrett misstates the types of risk that are relevant to an evaluation of a regulated entity's return on equity in a regulatory proceeding. Regulation is intended to serve as a substitute for competition where the regulator's obligation is to establish rates that provide the regulated entity with an opportunity to earn a fair rate of return defined as a return commensurate with the returns on investments of commensurate risk. To not consider company specific risks in arriving at a recommended or allowed return on common equity in a base rate proceeding violates the stand-alone principles of finance and ratemaking. It does so because it is the use of invested funds, not the source of those funds which gives rise to the risk of the investment. Also, because the rate of return to be set in this proceeding will be applied to PSO's rate base and PSO's alone, it is the total risk, the sum of all business and financial risks, of PSO's operations/rate base which are relevant establishing an allowed return on common equity in this proceeding.

Ms. Ahern testified that the financial literature supports the basic financial principle that it is the use of the funds invested which gives rise to the risk of the investment, not the source of those funds.

In other words, it is the "risks and uncertainties" surrounding the property employed for the "convenience of the public" which determines the appropriate level of rates. In this proceeding, the property employed "for the convenience of the public" is the rate base of PSO. Therefore, it is the total investment risk of PSO, and its rate base alone, which is relevant to the appropriate rate of return for the Company. Curiously, Witness D. Garrett implicitly agrees when he states that "[a]warded returns are set through the regulatory process and may be influenced by a number of factors other than objective market drivers. . . the cost of capital is driven by stock prices, dividend, growth rates, and most importantly – it is driven by risk."

In view of the foregoing, it is entirely appropriate and required that all the risks faced by PSO, including the risk of cost recovery disallowances, regulatory environment, and the like, be considered when setting PSO's allowed rate of return, including common equity cost rate.

According to Ms. Ahern, in Witness D. Garrett's discussion of systematic versus non-systematic risk in his Responsive Testimony he has confused the theory behind the Capital Asset Pricing Model ("CAPM") with the reality.

Witness D. Garrett's assumption that all investors hold well/fully diversified portfolios in which all non-systematic risk is diversified "away" is not realistic. The market is full of investors who hold less the fully diversified portfolios, e.g., money market fund investors. As noted by Morin, the CAPM "assumes that investors hold diversified portfolio and operate in capital markets unencumbered by transaction costs, taxes, and restrictions on borrowing and short-selling."

In addition, the assumption of investors holding diversified portfolios is inconsistent with the stand-alone principle of finance and regulation. It is the risk of investment in PSO's assets/rate base which gives rise to PSO's investment risk and hence its cost of common equity. Moreover, its shareholder, American Electric Power Company, Inc. ("AEP" or "the parent"), while holding a portfolio of assets, i.e., operating subsidiaries, is not fully diversified as most of these subsidiaries are regulated operating subsidiaries.

According to Ms. Ahern, the second issue concerns beta as a measure of the volatility of stock market returns, because beta is an incomplete measure of risk.

Ms. Ahern testified that Witness D. Garrett's assertion that the only relevant risk to estimating/allowing a return on common equity for PSO is market risk, as measured by beta, should be rejected by the OCC.

Ms. Ahern addressed Witness D. Garrett's financial risk discussion and his Figure 6 which purports to demonstrate the "Effect of Increasing Debt Ratio on Weighted Average Cost of Capital." According to Ms. Ahern, the example violates the financial theory of the relationship between leverage and financial risk formalized by Modigliani and Miller which holds the Weighted Average Cost of Capital ("WACC") constant, not the cost of common equity. Figure 6 also violates the basic financial principle of risk and return, i.e., investors require a greater return for bearing greater risk. As discussed previously, the greater the leverage in a company's capital structure, the higher the financial risk of the company which must be factored into the common equity cost rate. Hence, the assumption of a constant common equity cost rate, e.g., 9.0%, across all possible levels of debt in a capital structure, violates basic financial theory. Witness D. Garrett's conclusions should thus be disregarded by the OCC.

In response to Witness D. Garrett Figure 1: Awarded Returns on Equity vs. Market Cost of Equity (2005 – 2016), Ms. Ahern testified that the returns on the market (Market Cost of Equity) shown in Figure 1 are relative to market price during an unprecedented period of low interest rates orchestrated by the Federal Reserve's Federal Open Market Committee while the regulatory awarded returns are to be applied to book value. Because the cost of equity is a long-term concept, Witness D. Garrett's use of the 2005 – 2016 low interest rate time period is not representative of the long-term cost of equity, for either the market or for individual firms. Recreating the Market Cost of Equity over the entire 1961 – 2016 time period provided by OIEC, et al. Witness D. Garrett results in an average 10.27% Market Cost of Equity which still understate the true Market Cost of Equity because actual market returns over that period were 11.39%. Thus, any comparison between the market costs of equity over such a short time horizon, characterized by artificially low interest rates, and the awarded returns on equity shown in Figure 1 is an "apples and oranges" exercise and, therefore, meaningless.

In response to Witness D. Garrett's claim that it is not reasonable to look at the projected returns on book equity of non-regulated firms Ms. Ahern testified that Hope and Bluefield do not specify that the "firms of comparable risk" or the firms having "corresponding risks" be regulated utilities. Hence, it is reasonable to evaluate the projected returns on book common equity, as well as the expected market returns, of non-priced regulated firms of similar total risk, since utilities, such as PSO, compete with all other firms in the capital markets, regulated and non-regulated alike.

Moreover, by focusing only on beta, Witness D. Garrett has ignored the fact that the Non-Regulated Sample was selected based upon combined measures of total risk, i.e., betas as a measure of systematic risk and the standard errors of the regression giving rise to those betas.

According to Ms. Ahern, Witness Parcell's sole concern with Ms. Ahern's testimony is that the projected returns for the Non-Regulated Sample exceed the actual returns for the S&P 500 without providing any analysis of the risk of the Non-Regulated Sample relative to that of the S&P 500. Ms. Ahern testified that what Witness Parcell has ignored in his "disagreement" is the fact that the Non-Regulated Sample was selected upon mutually exclusive bases of a range of unadjusted betas for PSO Witness Vilbert's Electric Sample and standard errors of the regressions giving rise to those betas. Thus, his "disagreement" is misplaced.

The cost of capital, including the common equity cost rate, is a function of investor perceived risk. The Non-Price Regulated Sample was based upon selection criteria encompassing total investment risk, i.e., beta as a measure of systematic risk (i.e., market or non-diversifiable risk) and the standard error of the regression as a measure of unsystematic risk (i.e., company-specific risk). Companies which have similar betas and standard errors of regression have similar total investment risk, therefore, the Non-Regulated Group is similar in risk to PSO Witness Vilbert's Electric Sample and, hence, similar in risk to PSO.

Ms. Ahern addressed Witness Farrar's suggestions that the OCC require "that debt financing be used for large projects to reduce the capital costs" claiming that it would save ratepayers over the life of any debt issued, specifically $12.9 million at a 4.5% cost rate on the $223 million in Environmental Compliance Plan ("ECP") assets. Mathematically, this may be true, however, in his savings estimate AG Witness Farrar has ignored financial theory of risk and return. The greater the leverage in a company's capital structure, the greater the financial risk which increases common equity risk as well. Should PSO's credit quality and credit/bond rating be negatively affected by the pressure on cash flows due to the increase in leverage caused by financing large assets with debt alone, PSO's debt cost rate is likely to rise as well. His suggestion is, thus, not likely to save ratepayers anything, as both PSO's debt and common equity costs would increase.

In responding to Witness Farrar's suggestion that the OCC "delay the recovery of depreciation expense on PSO's Environmental Compliance Plan assets for a few years", Ms. Ahern testified that this is nothing more than "kicking the can down the road," pushing the annual $9.6 million depreciation expense to a future generation of ratepayers. In fact, those ratepayers would be paying more, as the delayed depreciation expense would be added to the annual depreciation expense over the asset's remaining life.

Ms. Ahern rebutted Witness Bohmann's proposed regulatory treatment of Northeastern Unit 4. According to Ms. Ahern, Witness Bohrmann supports his recommended regulatory treatment of Northeastern Unit 4 by citing an article which noted that "the U.S. electric utility industry's earnings before interest, taxes, depreciation, and amortization ('EBITDA') rose 16 percent on flat generation growth from 2012 to 2016, but has reportedly reduced the value of its assets by $55 billion during this period." However, Witness Bohrmann has not provided any support that this statement is applicable to PSO. Nor has Witness Bohrmann refuted what the financial community has been told concerning the regulatory treatment of Northeastern Unit 4. He has merely recounted it. Since there is no evidence contrary to the fact that "the Company's future net income and cash flow could be reduced and could impact the Company's financial condition," there is no basis for his proposal to spread the loss in value of the Northeastern Unit 4 between ratepayers and shareholders.

Relative to Witness Bohrmann's statement that his "proposal sends the appropriate signal to PSO and other regulated utilities in Oklahoma that utility management should always seek out creative solutions to maximize value for its ratepayers, in reality utility management should always seek out creative solutions to enable the utility to continue to provide safe and reliable service to its customers.

JOHN J. SPANOS

Mr. Spanos' rebuttal testimony presents a general discussion of depreciation principles and the depreciation study process. He discussed the objective of depreciation in allocating the full costs of the Company's assets (original cost less net salvage) over their service lives, explain the concept of intergeneration equity, and responds to incorrect concepts set forth in the testimonies of other parties. He then discusses the process and judgments involved in estimating service lives and net salvage. Mr. Spanos explains in detail, the depreciation study he performeded is consistent with accepted practices in the industry and established depreciation concepts.

In contrast, the other parties' proposals are inconsistent with accepted depreciation practices and lack the application of informed judgment. The other parties' (particularly OIEC and the AG) proposals for mass property service lives do not interpret the historical data in an appropriate manner and do not apply informed judgment in estimating service lives. As a result, the other parties estimates of service lives for the Company's assets are unreasonably long for the types of property studied. The AG's net salvage recommendations are not based on a widely-accepted method, and instead are based on the flawed premise that a utility should only accrue net salvage at a level that is similar to what it has spent in recent years. The result is that the AG's net salvage method results in net salvage estimates that will accrue far less than the full cost of the Company's assets for many accounts.

After a general discussion of depreciation principles, Mr. Spanos addressed in more detail the specific adjustments to the depreciation study that each witness proposes. These include:

- <u>Mass property service lives</u>. The currently approved depreciation rates are based on unreasonable and unrealistically long service life estimates. The recommendations in Mr. Spanos' depreciation study are much more reasonable for the Company's assets. PUD, OIEC and AG have recommended different service life estimates from mine for certain mass property accounts. The process of estimating service lives for mass property (e.g. transmission and distribution plant accounts) incorporates the results of statistical life analysis, but also must incorporate informed judgment. Authoritative depreciation sources are clear that judgment must be employed so that the resulting service lives are reflective of the property being studied and the future conditions in which it will operate.

OIEC and AG have proposed changes to the largest number of accounts. In each circumstance, both OIEC and AG have based their suggestions solely on mathematical curve matching without the application of judgment. The result is that Mr. Garrett's and Mr. Dunkel's estimates are unreasonable and unrealistic for the property studied. The inappropriateness of their mathematical approach is perhaps best seen in the wide variance between service lives Mr. Garrett recommended in the instant case and what he proposed in Cause No. PUD 201500208. Mr. Garrett's average service life estimates in the instant case are, for some accounts, less than half what he proposed only two years ago. A sound approach to estimating service lives would not produce such extreme changes in estimates in such a short period of time between studies.

PUD has also made changes to a few mass property accounts, which, while not as extreme as some of OIEC and the AG's estimates, also do not incorporate the requisite judgment which produces unreasonable service life estimates.

- Mass property net salvage. The AG proposes the most significant changes to net salvage estimates, as the AG has proposed to use an unorthodox and inappropriate methodology for determining net salvage estimates. The AG's proposal to depart from the longstanding and widely accepted net salvage method has no reasonable mathematical basis, no support in authoritative depreciation textbooks, and is not widely used in the industry. PUD and OIEC have used traditional and accepted methods for net salvage. PUD has recommended two changes to the Company's net salvage estimates for mass property accounts, and OIEC proposes no changes to my estimates.

- Terminal net salvage for production plant accounts. In order to recover the full cost (original cost less net salvage) of the Company's assets, net salvage estimates must be stated at the cost at which they will be incurred. Therefore, it is appropriate to escalate the estimated terminal net salvage costs for the Company's power plants to the year of the expected retirement of each facility. The approach recommended in the depreciation study of escalating these costs is consistent with depreciation principles and is accepted and supported by a large majority of jurisdictions and authoritative depreciation texts. I will not address the decommissioning study in detail, as that will be addressed in Mr. Meehan's rebuttal testimony.

- Amortization periods. There are additional proposals from the parties, which include a change in the life for software and changes to general plant amortization accounts. I also explain why the other parties' proposals for these issues are inappropriate.

According to Mr. Spanos, Mr. Garrett, on behalf of OIEC has submitted two proposals. In the first, OIEC proposes to continue using the current depreciation rates. In the second, OIEC proposes to use the results of Mr. Garrett's latest depreciation analyses. In my direct testimony, I explained that the current depreciation rates are based on very unrealistic estimates for many accounts, and are not appropriate. Mr. Garrett's proposals in the instant case actually support my view that the current estimates are inappropriate. Interestingly, many of the currently approved depreciation rates are based on service life estimates previously proposed by Mr. Garrett in Cause No. PUD 201500208. However, in this case, for these very same accounts, Mr. Garrett now proposes service lives that are, in many cases, considerably shorter than what he had proposed only two years ago. For example, in Cause No. PUD 201500208, Mr. Garrett proposed a 98-year average service life for Account 373, Street Lighting and Signal Systems. In the instant case, he has proposed a 44-year average service life for this account. That is, his life estimate in the instant case is less than half of what he proposed only two years ago. This confirms that the current depreciation rates are based on unreasonable estimates, Mr. Garrett, who initially proposed them, no longer arrives at the same conclusion. It also further highlights the flaws in Mr. Garrett's approach. If, in the span of only two years, Mr. Garrett can estimate lives that are more than 50 years apart, it suggests there is a serious flaw in his approach to estimating service lives. Thus, both of Mr. Garrett's options should be rejected. The Company's current depreciation rates are inadequate and proposed rates based on standard statistical analyses, properly interpreted, and the application of informed judgment, not mathematical curve fitting alone, should be adopted.

Mr. Spanos further testified that when Mr. Garrett argues that "it is better that useful lives are overestimated rather than underestimated" he is incorrect.

Mr. Spanos testified that in his view, which is shared by authorities on ratemaking principles, Mr. Garrett's opinion is fundamentally wrong. First, for Mr. Garrett to even make such a claim, he must dismiss the entire concept of intergenerational equity. He states that "unintentionally overestimating depreciable lives (i.e., underestimating depreciation rates) does not harm the Company" and argues that "if an asset's life is overestimated, there are a variety of measures that regulators can use to ensure the utility is not financially harmed." Nowhere in his discussion is there even an acknowledgment that such a situation would, by definition, result in intergenerational inequity. Mr. Garrett has not even considered the concept and the result that "overestimating depreciable lives" will most certainly harm future generations of customers who will unfairly be required to pay for assets that do not provide them service.

Further, Mr. Garrett does not acknowledge that if depreciation rates are too low (for example, if lives are "overestimated") the cost to customers will, over the long term, actually be higher, all else being equal. This occurs because accumulated depreciation is an offset to rate base. If depreciation expense is too low, then accumulated depreciation will be lower than it otherwise would be, producing a rate base that is higher than it otherwise would be. Thus, if customers pay too little in depreciation expense, they will have to pay a higher return on rate base, as rate base will be higher. As a result, over the long-term, depreciation rates that are too low actually produce a higher total cost to customers. Mr. Garrett's preferred approach to minimize depreciation expense is not only harmful to customers in that it is likely to produce intergenerational inequity, but also because it will likely result in higher customer rates over the long term.

Mr. Spanos testified that one of the foremost ratemaking texts is James Bonbright's Principles of Public Utility Rates. Bonbright addresses whether it is preferable to err on the side of higher depreciation as opposed to lower depreciation. Bonbright concludes that it is preferable to overestimate depreciation expense as opposed to underestimate depreciation expense. Bonbright refers to this as a criterion of "conservatism", and states:

> This criterion suggests that, as between two proposed methods of cost amortization, one of which undertakes faster write-offs than the other during the early years of useful service lives, any reasonable doubt may well be resolved in favor of the former unless, on consequence, the resulting temporarily higher rate levels will be a serious deterrent to the development of a demand for utility services commensurate with plant capacity.

Thus, Bonbright supports the exact opposite conclusion of Mr. Garrett's opinion on this matter.

Mr. Spanos testified that both OIEC and the AG recommended service lives that, for some accounts, are much too long to recover the Company's investments over their service lives. Each party has also recommended net salvage estimates that will not result in the full allocation of the Company's costs. Additionally, in Mr. Farrar's responsive testimony, the AG argues for the deferral of costs, which is a blatant disregard for the concept of equity. The fact of the matter is that PSO's depreciation rates, as established in prior cases, are too low. This is true for many of the unrealistic service life estimates used in calculating current depreciation rates. But it is also evidenced by the fact that, the Company was not afforded the opportunity to recover the costs of Northeastern Units 3 and 4 during their service lives, resulting in future customers having to pay the cost of assets from which they will receive no service. In order to limit the risk of similar problems in future depreciation studies, the other parties' recommendations must be rejected in order to ensure the equitable recovery of the Company's assets.

RESPONSIVE TESTIMONY

Public Utility Division

GEOFFREY M. RUSH

On June 30, 2017, PSO filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. The purpose of this testimony is to provide Mr. Rush's response to the five recommended revisions to the FCA Rider of PSO, which were outlined in the Rate Design Responsive Testimony of OIEC witness Scott Norwood that was filed on October 3, 2017.

Mr. Rush recommends the Commission reject Mr. Norwood's first, second, and third recommendations relating to FCA factors.

Mr. Rush recommends the Commission accept Mr. Norwood's fourth and fifth recommendations relating to FCA factors.

Mr. Rush believes Mr. Norwood's first recommendation, which would require PSO to file an application with the Commission to revise PSO's FCA Factor on an annual basis, requires revisions to 17 0.S. § 253 of the Oklahoma Statutes and OAC 165:35 and 165:50 of the Commission Rules. Adding FCA factor causes to the existing Commission case load will unnecessarily increase the workload of PUD, delay implementation of Fuel Factors, and unnecessarily burden Commission resources. Additionally, approving this recommendation would cause PSO's ratepayers to incur additional regulatory expenses.

Mr. Rush believes the Commission should reject Mr. Norwood's second and third recommendations because approval of these recommendations would result in substituting regulation for the utility's reasonable self-management, i.e., usurp the managerial discretion of the Company.

Mr. Norwood's second recommendation would eliminate the provision for interim FCA factor adjustments. In addition to Mr. Rush's belief that a utility's reasonable self-management should suffice, Mr. Rush believes PSO uses its best efforts to establish FCA factors that reduce variations in the balance in the over/under recovery account. Mr. Rush believes having a process that allows the utility the flexibility to make periodic adjustments to the FCA factor could reduce the potential rate shock experienced by ratepayers during large true-up events.

Mr. Norwood's third recommendation would modify the DEF$ term of the FCA formula to shorten the period during which accumulated fuel over-recovery balances are refunded to customers from 12 months to 1 month. In addition to Mr. Rush's belief that a utility's reasonable self-management should suffice, Mr. Rush believes that PSO's current refund policy is sufficient, which is to credit over-recoveries to customer classes using the same allocation method by which the FCA factor collected the revenue.

Mr. Rush does not object to Mr. Norwood's fourth recommendation, which would require PSO to provide to each party in the Company's most recent base rate or FCA revision proceeding electronic copies of monthly reports submitted to PUD. However, Mr. Rush notes the public, including the parties to the base rate case, already have the ability to request and obtain such reports.

Mr. Rush does not object to Mr. Norwood's fifth recommendation that would modify the term of the FCA formula to exclude explicitly net revenues earned from SPP energy sales from the margin sharing provision that currently applies to off-system sales. Mr. Rush believes that there are various operational complexities that create risk for a Market Participant that could increase costs; however, the ratepayer should retain fully any off-system sales that result from the utility's participation in the Integrated Marketplace.

For the reasons stated and supported in his Testimony, Mr. Rush believes that his recommendations are fair, just, reasonable, and in the public interest.

JASON C. CHAPLIN

Jason Chaplin is employed by the Public Utility Division ("PUD') of the Oklahoma Corporation Commission ("OCC" or "Commission") as an Energy Coordinator. Mr. Chaplin filed Rebuttal Testimony on October 16, 2017. The purpose of Mr. Chaplin's Rebuttal Testimony is to present PUD's response to the Southwest Power Pool Transmission Cost ("SPPTC") tariff recommendations, which was outlined in the Responsive Rate Design Testimony of Oklahoma Industrial Energy Consumers' witness Scott Norwood on October 3, 2017. PUD witness Geoffrey M. Rush will provide Rebuttal Testimony regarding Mr. Norwood's recommendations relating to the Fuel Cost Adjustment Rider.

Mr. Chaplin makes the following recommendations regarding Mr. Norwood's proposed recommendations related to PSO"s SPPTC tariff:

- PUD does not support Mr. Norwood"s first recommendation of requiring the Company to file an application with the OCC to revise the SPPTC tariff each year because PUD believes the Company's current annual redetermination process provides for an adequate level of review;

- PUD supports Mr. Norwood's second recommendation to make explicit that the Company has an ongoing obligation to provide testimony which addresses the reasonableness of third party charges recovered through the SPPTC in future base rate proceedings;

- PUD does not support Mr. Norwood's third recommendation to eliminate the current provision for the Company to implement interim adjustments to the SPPTC tariff at any time when an over-recovery or under-recovery of expenses exceeds 10%. PUD believes the 10% over-under provision, the annual re-determination process, and reviews in future base rate proceedings provide reasonable protections to customers by allowing multiple opportunities for review, not just review in future rate proceedings; and

- PUD does not support Mr. Norwood's fourth recommendation for this Commission not to adopt the provision to require a broader review of the SPPTC filing in instances when an SPPTC revision results in an increase that exceeds 50% because this broader review provides another mechanism for PUD to ensure customer protection while also incentivizing PSO to pursue cost control within the SPP organizational structure continually.

Finally, Mr. Chaplin testified that he believes these recommendations are fair, just, reasonable, and in the public interest.

JOHN O. AARON

Mr. Aaron testified that Mr. Schwartz, Dr. Blank, and Mr. Garrett reject PSO's request to allocate its transmission cost-of-service on a twelve coincident peak (12 CP) basis and support an allocation based on a four coincident peak (4 CP) basis.

According to Mr. Aaron, while historically PSO planned and built its transmission system to serve its own retail and wholesale native load, that is no longer the case today. Now, SPP has functional control of PSO's transmission assets to meet regional and local needs; therefore, what was done historically in regard to transmission planning and constructing as a basis for determining the appropriate transmission allocation, no longer exists. In other words, the justification for using 4 CP no longer exists.

According to Mr. Aaron, cost causation is the key element with PSO's request. The transmission costs were incurred by PSO as a direct result of providing service to its retail customers based on transmission charges from SPP. There is no need to reallocate the transmission costs and inappropriately shift the costs to other classes. PSO is a member and transmission customer of SPP, the regional transmission provider that bills its transmission service customers, like PSO, on a 12 CP basis. As a result, PSO also pays for transmission to serve its load on a 12 CP basis.

According to Mr. Aaron, the 12 CP allocation of transmission costs reflects how PSO's customers use the transmission system. The customers that benefit from the use of the transmission system also bear their appropriate share of the cost for their use of the transmission system. PSO's larger customers rely more heavily on the SPP transmission system; thus, they should bear a more equitable share of those costs billed by SPP than they currently do with the existing 4CP allocation.

PSO's recommendation to use a 12 CP appropriately allocates transmission costs based on actual use of the SPP transmission system.

Mr. Aaron testified that PSO agrees to allocate all charges recorded in FERC Account 565 (Transmission of Electricity by Others) on a 12 CP allocation. This allocation is consistent with Dr. Blank's testimony (page 4) regarding expenses recorded in FERC Account 565 and the billing practices of the transmission provider, and with the testimony of Mr. Schwartz since the transmission expenses currently recovered by PSO through the SPPTC are recorded in FERC Account 565.

Mr. Aaron testified that the updated retail base rate revenues are $596,009,058 for the six-month post-test year period. This amount reflects the update to all billing determinants and removes the adjustment for Energy Efficiency and Demand Response kWh and kW originally proposed by PSO.

JENNIFER L. JACKSON

Ms. Jackson testified that PSO was providing a revised proof of revenue statement in response to Mr. Farrar's responsive testimony. According to Ms. Jackson, her rebuttal EXHIBIT JLJ-1R included the updated billing determinant information and adjusted revenues and appropriately accounted for normalized billing determinant data associated with class customer counts that existed during June 2017, as well as the removal of the EE/DR program adjustment as discussed by Mr. Aaron. The revised proof of revenue also included the calculation of the compliance pro forma adjustment for all classes based on a revised M-6 work paper, which is sponsored by Mr. Aaron.

Ms. Jackson further testified that as shown in the filed WP M-6 (the adjusted normalized test year billing determinants) and the proof of revenue statement, the elements that determine the adjusted base rate revenues are billing determinants. These billing determinants include some or all of the following depending on the rate class:

- test year end customer count;
- fixture counts;
- energy (kWh);
- demand (kW);
- kVAR units

These billing determinants are associated with and normalized for the test year-end level of customers for each rate class, and any associated minimum bill or final bill revenue. In EXHIBIT JLJ-1R, all billing determinants have been updated and normalized based on a June 2017 customer count level.

Ms. Jackson presumed that the June 2017 adjusted base rate revenues and associated billing determinants will be used to update the originally filed current total base rate revenues and will be used in setting the final rates to be approved in the compliance phase of this Cause.

Ms. Jackson testified that PSO has proposed to move its major retail rate classes to the required cost-to-serve for each class.

Mr. Schwartz stated that it is PUD's position that the Company could have improperly included revenue adjustments related to its EE/DR. He also stated that this adjustment improperly affected the proposed allocation factors.

According to Ms. Jackson, as stated in Mr. Aaron's rebuttal testimony, PSO has agreed to remove the EE/DR adjustment and to adjust the class allocation factors accordingly as long as the associated kWh and kW are recovered through the DSM Rider.

Ms. Jackson further testified that Mr. Schwartz also has an issue with moving major classes to their cost-to-serve based on the large increase requested in this Cause.

PSO's proposal to move the major rate classes to their cost-to-serve takes into account the individual rate classes included in a major rate class category. Many individual rate classes would have experienced increases significantly higher than the system average increase in order to move the rate class to an equalized return. The system average base rate increase, as proposed by PSO, is 28.33%. This results in a total revenue increase, which includes fuel and rider revenues, of 11.43%.

According to Ms. Jackson, Mr. Farrar recommended that classes move to the true cost-of-service only if the Commission adopts the Attorney General's recommended revenue requirement. If the Attorney General's recommendation is not adopted, Mr. Farrar recommends a proportional increase be applied to all customers.

Ms. Jackson did not agree with Mr. Farrar because in past cases, PSO has recommended a revenue distribution methodology similar to Mr. Farrar's approach and the Commission has ruled against that methodology. In fact, the Commission ruled against that same methodology recently in PSO's last rate case, Cause No. PUD 201500208.

Ms. Jackson testified that Mr. Schwartz stated that PUD believes that changing the transmission allocator from a 4 CP to a 12 CP fails to represent a summer-peaking utility and creates a disconnect between the cost allocation and the current rate design and sends confusing signals to customers.

Ms. Jackson responded by stating that PSO's rate design is based on seasonal signals that indicate the cost to produce electricity is higher in the peak period due to increased usage. Customers have the choice to use and conserve electricity at their discretion being aware of the price they are paying during the on-peak season; for example, customers can turn the thermostat up in the summer to conserve energy by using less kWh. However; those air-conditioning kWh are not shifted to the off-peak. PSO's rates also include time-of-day rates that encourage shifting load from an on-peak period window, such as 2 p.m. to 7 p.m., to another time to avoid higher prices. This shift still, regardless of the time of day it occurs remains within the on-peak (summer) season; load is shifted from one hour of the day to another but not into the off-peak season. Secondly, PSO's rates recover all of the functional costs from production, transmission, and distribution services. Each of these functions has different allocation methodologies, even though PSO is a summer peaking utility. Finally, it is also important to note that PSO does not use a straight 4 CP allocator for its production function, even though PSO is a summer-peaking utility. The production function is allocated to the classes on a four coincident peak average and excess (4-CP A&E) allocation methodology. While this allocation methodology accounts for the summer-peaking nature of the generation costs, it also includes components for usage outside of the summer peaks, in essence, recognizing usage in all 12 months.

According to Ms. Jackson, Mr. Garrett stated that PSO has failed to consider that changing to a 12 CP methodology will skew price signals because PSO's industrial rates include a demand ratchet that is based on the customers' peak month's use rather than customers' 12 peak month's use. Mr. Garrett believes that a change to a 12 CP allocator would penalize industrial customers who have responded to PSO's price.

Ms. Jackson testified that industrial rate classes demand charges are based on the demand occurring during the peak period of the on-peak season (four summer months). Production costs are recovered through the peak demand charge. What Mr. Garrett fails to mention is there are two demands recorded for billing under the industrial rate schedule. The tariff requires a peak demand and a monthly maximum demand. The monthly maximum demand charge is based on the highest metered kW occurring during the month. The maximum demand charge is a charge based on maximum peak usage during the entire year, all 12 months, and recovers a portion of the transmission costs. According to Ms. Jackson, this illustrated that PSO's industrial rates are not inconsistent with PSO's proposed 12 CP transmission allocation methodology.

Ms. Jackson further testified that PSO can agree to update the industrial rates according to OIEC's proposal of an across-the-board charge only to the demand charge based on the final recommendations in the Commission's Order.

STEVEN L. FATE

Mr. Fate addressed Mr. Norwood's testimony beginning on page six where Mr. Norwood describes what he terms as "deficiencies" with PSO's FCA alleging that there is a lack of "transparency" and a "systematic or transparent process for review and approval." He goes on to criticize PSO for revising fuel factors "four times at different times of year since May 2015" and states that the changes were made with "relatively little regulatory oversight." He then claims that this "variability and frequency of changes" is difficult for customers, particularly large commercial and industrial customers' budgets.

According to Mr. Fate, PSO did change the FCA rates four times since May 2015; however, Mr. Norwood provides an incomplete explanation or context for the justified changes.

The May 2015 change was necessary to comply with the terms of the Final Order No. 639314 issued in Cause No. PUD 201300217. That Order adopted the terms of a Joint Stipulation and Settlement Agreement ("Stipulation") that required PSO to move all fuel-related costs from base rates and riders into the FCA. PSO would have been out of compliance with a Commission order if the May 2015 change did not occur.

The January 2016 change is an example of PSO exercising the interim change provision in the FCA tariff to reset factors to address an over-recovery. In anticipation of base rates changing in the December or January timeframe (either through a final order or interim rates), PSO elected to delay the on-cycle fuel change in November to coincide with the base rate change to avoid changing customers' rates two times within a very short period. This also enabled customers to receive an overall decrease on their bills.

The November 2016 change was an annual, on-cycle factor change where factors were adjusted to reflect the then current deferred fuel balance and a new 12-month forecast.

Finally, the most recent change, May 2017, adjusted for an unanticipated increase in natural gas prices. The Company, subject to PUD's review and approval, again elected to use the interim factor provision rather than allowing a forecasted significant under-recovery to accumulate until November.

In summary, the four changes were made for legitimate reasons. Mr. Norwood's characterization is incomplete, perhaps because providing more background shows that there is no chronic issue with interim factor changes as he wants the Commission to believe.

According to Mr. Fate, PSO implements fuel changes pursuant to the terms of the FCA tariff, which require approval from the Director of PUD prior to implementation. To comply with the tariff, PSO submits the proposed factors and a detailed filing package that includes information such as an explanation of the factors driving the change, estimated customer impacts, forecasted expenses by fuel type, forecasted kwh sales by class per month, SPP expenses and revenues, as well as costs related to purchased power. PUD conducts at least one onsite audit to review the detailed information and ask questions of Company personnel. Following the audit, there are usually additional questions and information requests made through phone and email communication. It is only after this thorough review that PSO receives approval from PUD to change factors. Mr. Norwood's assertion is either a lack of understanding of the process or a complete disregard of PUD's oversight.

Regarding Mr. Norwood's claim that the current process lacks transparency, there is nothing that prevents parties, such as OIEC, from requesting the information that PUD reviews. In fact, PSO has consistently made information available to OIEC for review. It is unclear on what basis OIEC is claiming a lack of transparency or what it hopes to gain from a docketed proceeding.

A docketed proceeding is unnecessary and Mr. Norwood's testimony makes no mention of the fuel prudence review that are conducted on an annual basis.

Mr. Fate disagreed that interim adjustment should be prohibited. Interim changes undergo the same PUD review and approval process as the on-cycle change. The provision exists so that the over/under balance does not get too far in either direction. It protects both the customers and the Company from significant swings that can otherwise occur if the deferral/accrual is too long.

Mr. Fate could support a modification of the FCA to reduce the over-recovery period as long as it applies to under-recovery as well.

Regarding Mr. Norwood's recommendations to provide FCA reports to parties, PSO submits a fuel report to PUD on a monthly basis. Further, Mr. Norwood neglected to acknowledge that OIEC's counsel has been provided the same reports each month for years. PSO is more than willing to provide the reports to other requesting parties, but there should be no requirement to do so without request from a party.

Mr. Fate summarized Mr. Norwood's arguments related to PSO's SPPTC tariff by testifying that Mr. Norwood repeats the arguments that OIEC Witness Mark Garrett made in the first phase of rebuttal testimony. Specifically, he claims that PSO failed to show that the amount of SPP charges collected through the SPPTC during the test year were reasonable. According to Mr. Fate, he addressed these unfounded arguments in his rebuttal testimony filed on October 11, 2017, where he demonstrated that the necessary information was supplied in direct testimony and in supporting work papers. The direct testimony of PUD Witness Jason Chaplin confirms that the information was provided.

Mr. Fate further testified that Mr. Norwood's first modification to the SPPTC is to require annual SPPTC revisions to take place in a formal docket with review and approval by the Commission. This is an unnecessary step as the currently approved SPPTC tariff outlines a thorough process that requires review and approval by the PUD. Mr. Chaplin details this comprehensive review in both his responsive testimony and in discovery requests from OIEC.

Much like Mr. Norwood's FCA issues, it appears that he is seeking a solution where there is no problem.

Mr. Norwood's second recommendation is to require the Company to provide testimony in every base rate case addressing the reasonableness of third party charges recovered through the SPPTC tariff. PSO is agreeable to this as we already provide that level of support in both testimony and supporting workpapers.

Finally, his third recommendation is to eliminate the provision that allows for an interim factor change when an over-recovery or under-recovery exceeds 10% of the annual SPP expenses reflected in the SPPTC tariff. PSO has never exercised that provision and has no issue eliminating it.

According to Mr. Fate, Mr. Norwood mistakenly thinks that PSO is requesting an addition to the SPPTC Tariff that requires a broader review if a SPPTC revision results in an increase that exceeds 50%, and he recommends that the revision be denied. The provision is not being requested by PSO. It was recommended by PUD in Cause No. PUD 201500208 and approved by the Commission in Final Order No. 657871. In preparing Schedule N for the immediate Cause, the Company discovered that the new language was inadvertently omitted from the Cause No. PUD 201500208 compliance tariffs. Therefore, the language was added to Schedule N in the immediate Cause to comply with the aforementioned order.

Regarding Mr. Bohrmann's recommendation to move fuel handling costs to base rates, Mr. Fate testified that PSO's fuel handling costs were included in base rates until May 2015 when they were moved to the FCA to comply with Order No. 639314 of Cause No. PUD 201300217. As previously discussed, that order approved a Stipulation that required PSO to move all fuel-related costs, including fuel handling, out of base rates and into the FCA. The change was initially recommended by PUD and was agreed to by all parties to the Stipulation, including the AG's office.

PSO does not need fuel handling costs to be in base rates to incentivize management to keep costs low. PSO's fuel handling costs in Cause No. PUD 201300217 were approximately $4.8 million. In the immediate Cause, PSO has provided evidence that they have decreased to approximately $3.2 million. PSO is focused on controlling costs for customers no matter what the recovery mechanism.

Mr. Fate further testified that if the Commission accepts Mr. Bohrmann's recommendation to move fuel handling costs out of the FCA and into base rates, $3.2 million needs to be added to the overall revenue deficiency in order for PSO to be made whole.

A. Naim Hakimi

Mr. Hakimi did not agree with the recommendations made by AG Witness Alexander and OIEC Witness Norwood to change the Commission-approved OSS margin sharing arrangement to eliminate the 10% OSS margins retained by the Company.

According to Mr. Hakimi, the Company's existing OSS margin sharing credits almost all of those margin benefits (90%) to the customers, while allowing the Company to retain only 10%. This treatment of sharing OSS margins has successfully aligned the interests of the customer and the Company. The introduction of the SPP IM has reinforced the need for a sharing mechanism.

According to Mr. Hakimi, Mr. Alexander's characterization of the SPP IM is overly simplistic.

The new markets, policies, procedures, requirements and responsibilities resulting from the deployment of the SPP IM are designed to minimize the cost for the SPP footprint as a whole. SPP is not tasked with optimizing the off-system sales margins for any one participant – whether that participant happens to be PSO, or any one of the dozens of other market participants. Instead, SPP is tasked first with maintaining reliability, and then with matching generation supply with load demand based on market prices. Mr. Alexander's cursory description of the SPP IM severely overstates the role of SPP in regards to the optimization of PSO's OSS margins, while at the same time fails to recognize the major role of AEPSC and PSO personnel in all phases of the SPP IM.

Mr. Hakimi testified that the processes undertaken by Commercial Operations, on behalf of PSO, in preparing and submitting its Day-Ahead Generation Resource Offers provides a good illustration of active involvement in the market. For example, the SPP rules allow the Company four different ways to choose how its units will participate in the SPP IM day-ahead market.

The table below describes the various status designations available within the Unit Commitment Status process. As indicated by the "Not Participating" Commitment Status, PSO is not required to offer every available unit into the Day-Ahead market. Rather, it must offer sufficient resources to meet its forecasted net real-time load obligation and its load ratio share of the SPP Operating Reserve requirements. Such a unit designation could be made to participate in the Real-Time market while opting out of the Day-Ahead market.

COMMITMENT	
Market	Resource is available for SPP economic commitment if it is off-line.
Self	Market Participant (MP) is committing the Resource and SPP should include it as committed in either the Day-Ahead (DA) Market and/or Reliability Unit Commitment (RUC) as specified.
Reliability	Resource is off-line and only available for commitment by SPP if there is an anticipated reliability issue.
Outage	Resource is unavailable due to a planned, forced, maintenance or other approved outage. The outage must be documented using the outage scheduler tool
Not Participating	Resource is otherwise available but has elected not to participate in the DA Market. This option is not available for use for Real-Time BalancingMarket (RTBM) Offers. **MPRR174**: This status does not automatically prevent a Resource from being cleared for off-line Supplemental Reserve.

Additionally, AEPSC, on behalf of PSO, optimizes the value of PSO's generation by participating in both the energy markets and the operating reserve markets. When preparing bids, coordinating unit status, and determining which units, and under what parameters to offer to the market, AEPSC bases its economic decisions in light of the total revenue expected.

Mr. Hakimi also testified that the SPP IM Day-Ahead market is designed to determine the least-cost solution to meet the Energy Bids and Reserve requirements for the entire SPP footprint. Commercial Operations, on behalf of PSO, is able to provide additional benefits in the form of lower purchased power cost used to serve customers and in capturing additional opportunities for off-system sales margins by extending its analysis of a unit's economic operation over a period of at least seven days. The projected economics of PSO's generation over this longer period of time is a major factor in determining how to offer those units in the SPP IM Day-Ahead market.

Mr. Hakimi testified that the SPP IM requires a significant level of attention to detail and market intelligence to optimize PSO's resources and serve its load. The ability of the Commercial Operations personnel to get the most value for PSO's generating resources also enables them to maximize the off-system sales margins for the benefit of the customers of PSO and the Company.

PSO customers benefit through three basic methods according to Mr. Hakimi:

1. Actively engaging with the range of markets to develop an intimate understanding of the vast web of interconnected activities and the financial impacts of those various activities.
2. Actively working to minimize the costs associated with supplying the customers' needs within the SPP framework.
3. Prudently identifying the opportunities for optimizing OSS margins.

But the crucial relationship that ties all three elements together is that the whole is greater than the sum of its parts. The activities of each method learn from and complement the other methods. For example, if the Company is an active participant in the forward markets, then it makes it much more difficult for other market participants to discern the Company's overall position. However, if PSO scales back its activity in the off-system bilateral market, and only goes out to the market to purchase energy to secure amounts to replace generating units that have forced outages, the market will quickly realize that PSO is only going to the market after the loss of a unit. This will drive up the market prices and result in higher purchased power costs after loss of generating units in the balance of the day and forward daily markets.

Mr. Hakimi also testified that the SPP IM has increased many fold the volume of information that is to be submitted to the SPP compared to the pre-IM operations. Participation in the SPP IM has led to significantly more activity to prepare the bids and assess the results of the market and be ready to implement the market results. In addition to the day-ahead energy market that did not previously exist, there are four new markets for the ancillary services in the day-ahead and real-time markets. For the day-ahead market alone, 88 data points have to be submitted to SPP for each generating unit for a given day.

Mr. Hakimi testified that the AG and OIEC's recommendations will send a signal that the work of the AEPSC Commercial Operations is not considered as bringing significant value to PSO and will have a detrimental effect.

The testimony of Mr. Alexander would lead one to believe that PSO's units automatically run in the SPP market. His testimony does not address the complexity of the market and the significant amount of additional information and coordination required by the Commercial Operations personnel to achieve the best results for PSO from the market. He also fails to consider the interconnected nature of the various areas in the SPP IM. The existence of the OSS margin sharing is a key driver for not only the successful optimization of OSS margins in the SPP IM and in the bilateral OSS market, but full participation in the IM will minimize the fuel, purchased power costs, and other SPP IM market charges.

Mr. Hakimi's recommendation is that the Commission keep the existing sharing mechanism (90/10) in place to continue to emphasize aggressive pursuit of off-system sales for the benefit of both the customers and the Company. While the SPP IM has introduced a new method of dispatching the Company's resources, it has also provided additional challenges for the Company and does not inherently change the focus of the aggressive pursuit of OSS transactions by the Company, which can occur in many different forms. Eliminating the OSS margins retained by PSO will send a message to the Commercial Operations personnel that their activity in the SPP IM to achieve the highest possible OSS margins is not as significant as it was previously. The recommendation of Attorney General witness Mr. Alexander to modify the OSS margin sharing treatment is not in the best interests of PSO's customers and the Company and therefore should not be adopted.

Mr. Hakimi did not agree with Mr. Norwood's recommendation to exclude from OSS energy sales in the SPP IM. In addition to the reasons given for rejection of Mr. Alexander's recommendation, which also overlaps with Mr. Norwood's recommendation regarding OSS margin sharing, the removal of margins from energy sales in the SPP IM recommended by Mr. Norwood fails to recognize the interrelated nature of SPP IM energy transactions with other OSS margin accounts. The artificial separation recommended by Mr. Norwood could provide outcomes where the Company shares in the losses for one part of the OSS transaction, but does not receive a share of the positive revenue from other parts of the transaction. His recommendation should therefore be rejected by the Commission.

MAUREEN L. RENO

The DoD/FEA filed the Responsive Testimony of Maureen L. Reno on September 21, 2017, in Cause No. PUD 201700151. Ms. Reno filed Supplemental Testimony on October 5, 2017.

In its response to DoD/FEA Data Request 2-9, PSO witness Michael Vilbert stated that as of August 31, 2017, he would exclude Sempra Energy and Vectren Corp. from his sample of proxy companies, and he would include Duke Energy, NextEra Energy, and Unitil Corp.

In accordance with Mr. Wilbert's stated criteria, Ms. Reno had excluded Sempra Energy because it was recently involved in substantial merger and acquisition activities. However, Ms. Reno had included CVectren Corp. because she had been unaware of a news report dated August 22, 2017, indicating that, based on anonymous sources, Vectren was considering options including a potential sale. Based on this news report, Ms. Reno agreed with Mr. Vilbert that Vectren should be excluded from her sample of proxy companies. Ms. Reno also agreed with Mr. Vilbert that Duke Energy and NextEra Energy should be included because their mergers had been completed more than five years before. However, Ms. Reno disagreed with Mr. Vilbert regardeing Unitil Corp. because there is incomplete data on the company to calculate consistent results across all her analyses.

Ms. Reno performed the same analyses set forth in her Responsive Testimony with the modified sample (excluding Vectren and including Duke Energy and NextEra Energy). Applying her analysis to the modified sample proxy group yielded only marginal changes to her prior ROE estimates. Her new range, based on her DCF model sensitivities, became 7.39 percent to 8.62 percent, with a midpoint of 8.01 percent. In comparison, her original estimate range was 7.33 percent to 8.57 percent, with a midpoint of 7.95 percent. Since both the original midpoint and new midpoint round to 8.0 percent, her original ROE recommendation of 8.0 does not change.

ATTACHMENT "B"

HEARING EXHIBITS

Exhibit 1 – PSO's Response to Oklahoma Attorney General's 9th Data Requests
Exhibit 2 – PSO's Response to OIEC's 21st Data Requests
Exhibit 3 – PSO's Response OIEC's 14th Data Requests
Exhibit 4 - PSO's Response to Attorney General's 25th Data Requests
Exhibit 5 – PSO's Response to OIEF's 14th Data Requests
Exhibit 6 – No Exhibit
Exhibit 7 – PSO's Response to OIEC's 21st Data Requests
Exhibit 8 – PSO's Response to OIEC's 21st Data Requests
Exhibit 9 – PSO's Response to OIEC's 21st Data Requests
Exhibit 10 – PSO's Response to OIEC's 22nd Data Requests
Exhibit 11 – PSO's Response to OIEC's 17th Data Requests
Exhibit 12 – Exhibit MLR-1S, ROE Witness Comparisons
Exhibit 13 – Errata ROW and Recommendation
Exhibit 14 – Treasury Security Yield Curve
Exhibit 16 – Federal Reserve press release 9/20/17
Exhibit 17 – CNBC Article 10/18/17
Exhibit 18 – Industry Overview: Electric Utilities
Exhibit 19 – Forecasted Dividends ROE
Exhibit 20 – RRA Regulatory Focus
Exhibit 21 – Exhibit MFG-11, Schedule 1, ROE and ROR Analysis
Exhibit 22 – Exhibit MFG- SR-1, 30 Year Treasuries Interest Rates, 2015-2017
Exhibit 23 – How to Read a Value Line Report
Exhibit 24 – PSO's Response to OIEC's 5th Data Requests
Exhibit 25 – PSO's Response to OIEC's 19th Data Requests
Exhibit 26 – PSO's Response to OIEC's 5th Data Requests
Exhibit 27 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 28 – Public Utility Depreciation Practices
Exhibit 29 – Federal Reserve Bulletin
Exhibit 30 – PSO's Response to Attorney General's 19th Data Requests
Exhibit 31 – Response Testimony of David J. Garrett from Cause PUD 201500208
Exhibit 32 – PSO's Attorney General's 4th Data Requests
Exhibit 33 – Direct Testimony of John J. Spanos
Exhibit 34 – Direct Testimony of John J. Spanos
Exhibit 35 – Depreciation Systems
Exhibit 36 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 37 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 38 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 39 – PSO's Response to Attorney General's 21st Data Requests
Exhibit 40 – Exhibit WWD-SR-2, PSO's Poles in Service 2002-2016
Exhibit 41 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 42 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 43 – Attorney General's 23rd Set of Data Requests
Exhibit 44 – PSO's Response to Attorney General's 23rd Data Requests

Exhibit 45 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 46 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 46A- Updated Exhibit 46 with page that was left out of the originally offered exhibit
Exhibit 47 – Photos of Substation
Exhibit 48 – FERC Part 101, Conservation of Power and Water Resources
Exhibit 49 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 50 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 51 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 52 – Responsive Testimony of William W. Dunkel
Exhibit 53 – WWD-SR-3, Percent Surviving at each age for 60 R 1
Exhibit 54 – Exhibit WWD-SR-4, Account 369.00 - Services
Exhibit 55 – Public Utility Depreciation Practices (NARUC)
Exhibit 56 – *Penn Sheraton Hotel v. Pennsylvania Public Utility Commission*
Exhibit 57 – *Lindhelmer vs. Illinois Bell Telephone Co.*
Exhibit 58 – Order of the Indiana Utility Regulatory Commission, Cause 44075
Exhibit 59- Revised Workpapers of D. Garrett
Exhibit 60- PSO's Response to Attorney General's 3rd Data Requests
Exhibit 61- PSO's Response to PUD's 2nd Data Requests
Exhibit 62- PSO's Response to the Attorney General's 6th Data Requests
Exhibit 63- PSO's Response to the Attorney General's 14th Data Requests
Exhibit 64- Exhibit TFB-SR-1, PSO Coal Consumption and Generation Mix Charts

ATTACHMENT "C"

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES AND THE ELECTRIC SERVICE RULES, REGULATIONS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	**CAUSE NO. PUD 201700151**

ALJ ACCOUNTING EXHIBIT
DECEMBER 11. 2017

Public Service Company of Oklahoma
Index to ALJ's Revenue Requirement Exhibit
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Schedule

Public Service Company of Oklahoma
ALJ's Revenue Requirement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description		(A) Total Company Pro Forma Amount	Reference		(B) ALJ Total Company Adjusted Amount
1	Pro Forma Rate Base	$	2,527,472,526	B-1	$	2,440,996,529
2	Rate of Return		7.220%	F-1		6.734%
3	Operating Income Required	$	182,483,516	1 times 2	$	164,376,706
4	Pro Forma Operating Income	$	78,943,783	H-1	$	218,613,087
5	Difference	$	103,539,733	3 minus 4	$	(54,236,381)
6	Revenue Conversion Factor		1.63867069			1.63076803
7	**PSO Pro Forma Base Rate Revenue Increase/(Decrease)**	**$**	**169,667,526**	5 times 6		
8	**ALJ Pro Forma Base Rate Revenue Increase/(Decrease) Difference to Application**			5 times 6	**$**	**(88,446,956)**
9	**ALJ Pro Forma Base Rate Revenue Increase/(Decrease)**			7 plus 8	**$**	**81,220,570**
10	Rev Inc Minus Difference	$	66,127,793	7 minus 5	$	(34,210,575)
11	Return Requirement	$	182,483,516	Line 3	$	164,376,706
12	Total Operating Expense	$	564,291,919	H-1	$	507,269,898
13	Income Taxes	$	74,840,260	H-1	$	64,734,906
14	**Revenue Requirement**	**$**	821,615,695	Line 8+9+10	**$**	736,381,510

Public Service Company of Oklahoma
ALJ Pro Forma Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description		(A) Total Company Pro Forma Rate Base		(B) ALJ Total Company Test Year Adjustments		(C) ALJ Total Company Pro Forma Rate Base	(D) Oklahoma Allocation Factor		(E) ALJ Oklahoma Jurisdictional Rate Base
	Plant in Service:									
1	Plant in Service	$	4,983,250,552	$	(14,083,293)	$	4,969,167,259	99.96043421%	$	4,967,201,169
2	Environmental Investment	$	-	$	-	$	-	0.00000000%	$	-
3	Less: Accumulated Depreciation	$	(1,502,061,083)	$	(32,673,645)	$	(1,534,734,728)	99.95754326%	$	(1,534,083,130)
4	Plant Held for Future Use	$	-	$	-	$	-	0.00000000%	$	-
5	Net Plant	$	3,481,189,469	$	(46,756,938)	$	3,434,432,531	99.96172608%	$	3,433,118,039
	Other Rate Base Investment									
6	Cash Working Capital	$	(110,725,044)	$	3,420,650	$	(107,304,394)	99.95680515%	$	(107,258,044)
7	Prepayments	$	96,929,116	$	(344,729)	$	96,584,387	99.96039220%	$	96,546,132
8	Material & Supplies	$	62,391,612	$	(5,596,294)	$	56,795,318	99.95887809%	$	56,771,963
	Rate Base Additions & Reductions									
9	Customer Deposits	$	(49,674,708)	$	(986,714)	$	(50,661,422)	100.00000000%	$	(50,661,422)
10	Customer Advances for Construction	$	-	$	-	$	-	0.00000000%	$	-
11	Off System Sales Trading Credits	$	(63,582)	$	84,403	$	20,821	99.94369994%	$	20,809
12	Regulatory Assets	$	127,004,496	$	3,919,384	$	130,923,880	99.96885747%	$	130,883,107
13	Regulatory Liabilities/Deferred credit	$	(33,427,564)	$	(857,855)	$	(34,285,419)	99.96020114%	$	(34,271,774)
14	Accu. Deferred Income Taxes	$	(1,041,197,914)	$	(39,357,904)	$	(1,080,555,818)	99.96364631%	$	(1,080,162,996)
15	Excess Deferred Income Taxes	$	(4,937,384)	$	-	$	(4,937,384)	99.96364631%	$	(4,935,589)
16	Deferred Investment Tax Credits	$	(15,971)	$	-	$	(15,971)	99.96048177%	$	(15,965)
17	**Rate Base**	$	2,527,472,526	$	(86,475,997)	$	2,440,996,529	99.96059089%	$	2,440,034,260

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section B
Schedule 2

Line No.	Description	(A) Total Company Pro Forma Rate Base	(B) ALJ Adjustment No. 1	(C) ALJ Adjustment No. 2	(D) ALJ Adjustment No. 3	(E) ALJ Adjustment No. 4	(F) ALJ Adjustment No. 5	(G) ALJ Adjustment No. 6	(H) ALJ Adjustment No. 7
	Plant in Service:								
1	Plant in Service	$ 4,983,250,552			$ 69,196,225				
2	Environmental Investment	$ -							
3	Less: Accumulated Depreciation	$ (1,502,061,083)							
4	Plant Held for Future Use	$ -							
5	Net Plant	$ 3,481,189,469	$ -	$ -	$ 69,196,225	$ -	$ -	$ -	$ -
	Other Rate Base Investment								
6	Cash Working Capital	$ (110,725,044)	$ 3,420,650						
7	Prepayments	$ 96,929,116						$ (344,729)	
8	Material & Supplies	$ 62,391,612				$ (5,886,208)	$ 289,914		
9	Fuel Inventories	$ -							
	Rate Base Additions & Reductions								
10	Customer Deposits	$ (49,674,708)		$ (986,714)					
11	Customer Advances for Construction	$ -							
12	Off System Sales Trading Credits	$ (63,582)							$ 84,403
13	Regulatory Assets	$ 127,004,496							
14	Regulatory Liabilities/Deferred credits	$ (33,427,564)							
15	Accu Deferred Income Taxes	$ (1,041,197,914)							
16	Excess Deferred Income Taxes	$ (4,937,384)							
17	Deferred Investment Tax Credits	$ (15,971)							
18	Rate Base	$ 2,527,472,526	$ 3,420,650	$ (986,714)	$ 138,392,450	$ (5,886,208)	$ 289,914	$ (344,729)	$ 84,403

Line No.	Description	(I) ALJ Adjustment No 8	(J) ALJ Adjustment No. 9	(K) ALJ Adjustment No 10	(L) ALJ Adjustment No. 11	(M) ALJ Adjustment No. 12	(N) ALJ Adjustment No. 13	(O) ALJ Adjustment No 14	(P) ALJ Adjustment No. 15	(Q) ALJ Adjustment No 16
	Plant in Service:									
1	Plant in Service									
2	Environmental Investment									
3	Less: Accumulated Depreciation				$ (32,673,645)					
4	Plant Held for Future Use									
5	Net Plant	$ -	$ -	$ -	$ (32,673,645)	$ -	$ -	$ -	$ -	$ -
	Other Rate Base Investment									
6	Cash Working Capital									
7	Prepayments									
8	Material & Supplies									
9	Fuel Inventories									
	Rate Base Additions & Reductions									
10	Customer Deposits									
11	Customer Advances for Construction									
12	Off System Sales Trading Credits									
13	Regulatory Assets			$ 4,625,004		$ 13,082,073	$ 968,689	$ 531,524	$ (1,139,884)	$ (12,738,287)
14	Regulatory Liabilities/Deferred credits	$ (69,740)	$ (788,115)							
15	Accu. Deferred Income Taxes									
16	Excess Deferred Income Taxes									
17	Deferred Investment Tax Credits									
18	Rate Base	$ (69,740)	$ (788,115)	$ 4,625,004	$ (32,673,645)	$ 13,082,073	$ 968,689	$ 531,524	$ (1,139,884)	$ (12,738,287)

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section B
Schedule 2

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Apr 27 2018

Line No.	Description	(R) ALJ Adjustment No. 17	(S) ALJ Adjustment No. 18	(T) ALJ Adjustment No. 19	(U) ALJ Adjustment No. 20	(W) Total ALJ Adjustments	(X) ALJ Total Company Pro Forma Rate Base
	Plant in Service:						
1	Plant in Service			$ (83,279,518)		$ (14,083,293)	$ 4,969,167,259
2	Environmental Investment					$ -	$ -
3	Less: Accumulated Depreciation					$ (32,673,645)	$ (1,534,734,728)
4	Plant Held for Future Use					$ -	$ -
5	Net Plant	$ -	$ -	$ (83,279,518)	$ -	$ (46,756,938)	$ 3,434,432,531
	Other Rate Base Investment						
6	Cash Working Capital					$ 3,420,650	$ (107,304,394)
7	Prepayments					$ (344,729)	$ 96,584,387
8	Material & Supplies					$ (5,596,294)	$ 56,795,318
9	Fuel Inventories					$ -	$ -
	Rate Base Additions & Reductions						
10	Customer Deposits					$ (986,714)	$ (50,661,422)
11	Customer Advances for Construction					$ -	$ -
12	Off System Sales Trading Credits					$ 84,403	$ 20,821
13	Regulatory Assets	$ (7,773,107)			$ 6,363,372	$ 3,919,384	$ 130,923,880
14	Regulatory Liabilities/Deferred credits					$ (857,855)	$ (34,285,419)
15	Accu. Deferred Income Taxes		$ (39,357,904)			$ (39,357,904)	$ (1,080,555,818)
16	Excess Deferred Income Taxes					$ -	$ (4,937,384)
17	Deferred Investment Tax Credits					$ -	$ (15,971)
18	Rate Base	$ (7,773,107)	$ (39,357,904)	$ (83,279,518)	$ 6,363,372	$ (86,475,997)	$ 2,440,996,529

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

ALJ Adj. No.	Adjustment Description		(A) Impact On Rate Base Increase		(B) Impact On Rate Base Decrease		(C) Net Incr/(Decr)
1	Adjust Cash Working Capital	$	3,420,650	$	-	$	3,420,650
2	Customer Deposits - ALJ 50	$	-	$	(986,714)	$	(986,714)
3	To adjust Plant in Service to 6/30/17 Balances - ALJ 11	$	69,196,225	$	-	$	69,196,225
4	Materials and Supplies - ALJ 20	$	-	$	(5,886,208)	$	(5,886,208)
5	Fuel Inventories - ALJ 21	$	289,914	$	-	$	289,914
6	Prepayment Expense - ALJ 16	$	-	$	(344,729)	$	(344,729)
7	Off-System Trading Deposits - ALJ 23	$	84,403	$	-	$	84,403
8	Adjust CIAC to 6/30/17 Balances - ALJ 31	$	-	$	(69,740)	$	(69,740)
9	Deferred Pole Attachment Regulatory Liability - ALJ 40	$	-	$	(788,115)	$	(788,115)
10	Deferred Storm Expense Regulatory Asset - ALJ 34	$	4,625,004	$	-	$	4,625,004
11	Accumulated Depreciation - ALJ 14	$	-	$	(32,673,645)	$	(32,673,645)
12	Deferred Enviro - Correct 12/31/16 Balances – ALJ 38A	$	13,082,073	$	-	$	13,082,073
13	Deferred Enviro - Reverse Half Year 2018 Amortization – ALJ 38B	$	968,689	$	-	$	968,689
14	Deferred Enviro. - Correct Company Exhibit Errors – ALJ 38C	$	531,524	$	-	$	531,524
15	Deferred Enviro. - Remove Carrying Costs thru 6/30/17 - ALJ 38D	$	-	$	(1,139,884)	$	(1,139,884)
16	Deferred Enviro. - Remove Estimated Costs 7/1/17 - 12/31/17 - ALJ 38E	$	-	$	(12,738,287)	$	(12,738,287)
17	Non-AMI Meters - Update to 6/30/17 - ALJ 42	$	-	$	(7,773,107)	$	(7,773,107)
18	Accumulated Deferred Income Tax - ALJ 26	$	-	$	(39,357,904)	$	(39,357,904)
19	Remove Return on NE 4 as of 6/30/17 - ALJ 59	$	-	$	(83,279,518)	$	(83,279,518)
20	Deferred Severe Storm Expense - ALJ 47	$	6,363,372	$	-	$	6,363,372
	Total Rate Base Adjustments	$	**98,561,854**	$	**(185,037,851)**	$	**(86,475,997)**

Public Service Company of Oklahoma
Cash Working Capital
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma	(B) Adjustments	(C) ALJ Total Company Pro Forma	(D) Net Lead/Lag Days	(E) ALJ Adjusted CWC
	Cost of Service					
1	Fuel & Purchase Power					
2	Coal	$ 51,773,532	$ -	$ 51,773,532	(12.1200)	$ (1,719,165)
3	Oil	$ 348,768	$ -	$ 348,768	(10.4400)	$ (9,976)
4	Gas	$ 102,768,020	$ -	$ 102,768,020	(37.4400)	$ (10,541,465)
5	Purchased Power	$ 467,644,014	$ -	$ 467,644,014	(25.0600)	$ (32,107,285)
6	Other O & M	$ 328,488,268	$ (20,057,561)	$ 308,430,707	(35.9500)	$ (30,378,312)
7	Federal Income Tax-Current	$ (27,977,860)	$ (8,550,684)	$ (36,528,544)	(33.6800)	$ 3,370,634
8	Federal Income Tax-Deferred	$ 77,402,260	$ -	$ 77,402,260	0.0000	$ -
9	State Income Tax-Current	$ (1,920,410)	$ (1,554,670)	$ (3,475,080)	(33.6800)	$ 320,659
10	State Income Tax-Deferred	$ 8,472,557	$ -	$ 8,472,557	0.0000	$ -
11	Taxes other than Income	$ 40,586,901	$ (49,673)	$ 40,537,228	(187.66)	$ (20,841,688)
12	Interest on Customer Deposits	$ 846,779	$ -	$ 846,779	(163.94)	$ (380,331)
13	Depreciation Expense	$ 180,664,161	$ (24,244,758)	$ 156,419,403	0.0000	$ -
14	Interest Long Term Debt	$ 59,901,099	$ (2,086,096)	$ 57,815,003	(85.2300)	$ (13,500,199)
15	Preferred Dividends	$ -	$ -	$ -	0.0000	$ -
16	Return	$ 122,582,418	$ -	$ 122,582,418	0.0000	$ -
17	Subtotal	$ 1,351,679,408	$ (54,457,346)	$ 1,288,749,505		$ (105,787,128)
18	Working Funds and Other					$ (1,517,266)
19						$ (107,304,394)
20				Company Pro Forma		$ (110,725,044)
21				**ALJ Adjustment to Rate Base**		$ 3,420,650
22						$ 3,420,650
23						$ (107,304,394)

0

Public Service Company of Oklahoma
Capital Structure
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Company Capitalization Ratios	(B) Company Cost of Capital	(C) Company Weighted Cost of Capital
	PSO Requested Capital Structure:			
1	Long Term Debt	51.4900%	4.6000%	2.3685%
2	Preferred Stock	0.0000%	0.0000%	0.0000%
3	Common Stock	48.5100%	**10.0000%**	4.8510%
4	Total	100.0000%		7.2195%

Line No.	Description	ALJ Capitalization Ratios	ALJ Cost of Capital	ALJ Weighted Cost of Capital
	ALJ Requested Capital Structure:			
1	Long Term Debt	51.4900%	4.6000%	2.3685%
2	Preferred Stock	0.0000%	0.0000%	0.0000%
3	Common Stock	48.5100%	**9.0000%**	4.3659%
4	Total	100.0000%		6.7344%

Section II
Schedule 1

Public Service Company of Oklahoma
ALJ Pro Forma Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Income Statement	(B) Total ALJ Adjustments	(C) ALJ Total Company Pro Forma Income Statement	(D) ALJ Recommended Increase	(E) ALJ Pro Forma Results	(F) Oklahoma Allocation Factor	(G) ALJ Oklahoma Jurisdiction Amounts
1	Operating Revenue:							
2	Electric	$ 821,615,695	$ 3,212,771	$ 824,828,466	$ (88,446,956)	$ 736,381,510	99.95891628%	$ 736,078,977
3	Other	$ -	$ -	$ -		$ -	0.00000000%	$ -
4	Total Operating Revenue	$ 821,615,695	$ 3,212,771	$ 824,828,466	$ (88,446,956)	$ 736,381,510		$ 736,078,977
5	Operating Expense:							
6	Fuel & Purchased Power	$ -	$ -	$ -	$ -	$ -	100.00000000%	$ -
7	Other O&M	$ 340,540,556	$ (20,057,561)	$ 320,482,995	$ -	$ 320,482,995	99.95668322%	$ 320,344,172
8	Other Expenses	$ 2,500,301	$ (12,670,029)	$ (10,169,728)	$ -	$ (10,169,728)	99.94232571%	$ (10,163,863)
9	Other Taxes	$ 40,586,901	$ (49,673)	$ 40,537,228	$ -	$ 40,537,228	99.96035419%	$ 40,521,157
10	Depreciation & Amortization	$ 180,664,161	$ (24,244,758)	$ 156,419,403	$ -	$ 156,419,403	99.96088078%	$ 156,358,213
11	Interest on Special Items	$ -	$ -	$ -	$ -	$ -		$ -
12	Total Operating Expenses	$ 564,291,919	$ (57,022,021)	$ 507,269,898	$ -	$ 507,269,898	99.95855875%	$ 507,059,679
13	Operating Income Before Income tax	$ 257,323,776	$ 60,234,792	$ 317,558,568	$ (88,446,956)	$ 229,111,612	99.95970785%	$ 229,019,298
14	Less: Income Tax	$ 74,840,260	$ 24,105,221	$ 98,945,481	$ (34,210,575)	$ 64,734,906	99.96002498%	$ 64,734,906
15	Operating Income	$ 182,483,516	$ 36,129,571	$ 218,613,087	$ (54,236,381)	$ 164,376,706	99.94383997%	$ 164,284,392

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description		(A) Total Company Pro Forma Income Statement		(B) ALJ Adjustment No. 1		(C) ALJ Adjustment No. 2		(D) ALJ Adjustment No. 3		(E) ALJ Adjustment No. 4		(F) ALJ Adjustment No. 5
1	Operating Revenue:												
2	Electric	$	821,615,695										
3	Other	$	-										
4	Total Operating Revenue	$	821,615,695	$	-	$	-	$	-	$	-	$	-
5	Operating Expense:												
6	Fuel & Purchased Power	$	-										
7	Other O&M	$	340,540,556	$	(1,244,786)	$	(117,876)	$	(8,264,000)	$	(7,970,720)	$	(96,780)
8	Other Expenses	$	2,500,301										
9	Other Taxes	$	40,586,901										
10	Depreciation & Amortization	$	180,664,161										
11	Interest on Special Items	$	-										
12	Total Operating Expenses	$	564,291,919	$	(1,244,786)	$	(117,876)	$	(8,264,000)	$	(7,970,720)	$	(96,780)
13	Operating Income Before Income tax	$	257,323,776	$	1,244,786	$	117,876	$	8,264,000	$	7,970,720	$	96,780
14	Less: Income Tax	$	74,840,260										
15	Operating Income	$	182,483,516										

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section II
Schedule 2

Line No.	Description	(G) ALJ Adjustment No. 6	(H) ALJ Adjustment No. 7	(I) ALJ Adjustment No. 8	(J) ALJ Adjustment No. 9	(K) ALJ Adjustment No. 10	(L) ALJ Adjustment No. 11	(M) ALJ Adjustment No. 12	(N) ALJ Adjustment No. 13
1	Operating Revenue:								
2	Electric								$ 505,152
3	Other								
4	Total Operating Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 505,152
5	Operating Expense:								
6	Fuel & Purchased Power								
7	Other O&M	$ (253,082)			$ (2,110,317)				
8	Other Expenses		$ (2,219,213)	$ (13,994,625)					
9	Other Taxes								
10	Depreciation & Amortization					(1,380,888)	$ (17,870,697)	$ (4,993,173)	
11	Interest on Special Items								
12	Total Operating Expenses	$ (253,082)	$ (2,219,213)	$ (13,994,625)	$ (2,110,317)	$ (1,380,888)	$ (17,870,697)	$ (4,993,173)	$ -
13	Operating Income Before Income ta)	$ 253,082	$ 2,219,213	$ 13,994,625	$ 2,110,317	$ 1,380,888	$ 17,870,697	$ 4,993,173	$ 505,152
14	Less: Income Tax								
15	Operating Income								

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section II
Schedule 2

Line No	Description	(O) ALJ Adjustment No. 14	(P) ALJ Adjustment No. 15	(Q) ALJ Adjustment No. 16	(S) Adjustment Income Tax	(T) Total Company Adjustments	(U) Pro Forma Income Statement
1	Operating Revenue:						
2	Electric	$ 2,707,619				$ 3,212,771	$ 824,828,466
3	Other					$ -	$ -
4	Total Operating Revenue	$ 2,707,619	$ -	$ -		$ 3,212,771	$ 824,828,466
5	Operating Expense:						
6	Fuel & Purchased Power					$ -	$ -
7	Other O&M					$ (20,057,561)	$ 320,482,995
8	Other Expenses			$ 3,543,809		$ (12,670,029)	$ (10,169,728)
9	Other Taxes		$ (49,673)			$ (49,673)	$ 40,537,228
10	Depreciation & Amortization					$ (24,244,758)	$ 156,419,403
11	Interest on Special Items					$ -	$ -
12	Total Operating Expenses	$ -	$ (49,673)	$ 3,543,809		$ (57,022,021)	$ 507,269,898
13	Operating Income Before Income ta›	$ 2,707,619	$ 49,673	$ (3,543,809)		$ 60,234,792	$ 317,558,568
14	Less: Income Tax				$ 24,105,221	$ 24,105,221	$ 98,945,481
15	Operating Income				$ (24,105,221)	$ 36,129,571	$ 218,613,087

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

ALJ Adj. No.	Adjustment Description		(A) IMPACT ON REVENUE REQUIREMENT Decrease		(B) Increase		(C) Net Incr/(Decr)
1	Factoring Expense Adjustment	$	(1,244,786)	$	-	$	(1,244,786)
2	Dues and Donation - ALJ 88 B	$	(117,876)	$	-	$	(117,876)
3	Storm Cost - ALJ 90-92	$	(8,264,000)	$	-	$	(8,264,000)
4	Incentive Compensation (STI & LTI) - ALJ 83	$	(7,970,720)	$	-	$	(7,970,720)
5	Supplemental Executive Retirement Plan (SERP) PSO - ALJ 80	$	(96,780)			$	(96,780)
6	Supplemental Executive Retirement Plan (SERP) AEPSC - ALJ 80	$	(253,082)	$	-	$	(253,082)
7	Decrease Regulatory Debits Expense to Correct Non-AMI Meter Amortization Rate - ALJ 44	$	(2,219,213)	$	-	$	(2,219,213)
8	SPP Schedule 9 NITS Transmission Expense - ALJ 94	$	(13,994,625)	$	-	$	(13,994,625)
9	Generation O&M Expense - ALJ 97	$	(2,110,317)	$	-	$	(2,110,317)
10	Decrease Production Depreciation due to PSO's extension of the useful life of the Oklaunion ARO from 2020 to 2046 - ALJ 38F		(1,380,888)	$	-	$	(1,380,888)
11	Depreciation Expense Accounts 356, 362, 366, 367, 373 and 390 - ALJ 107	$	(17,870,697)	$	-	$	(17,870,697)
12	Depreciation Expense Account 303 - ALJ 107	$	(4,993,173)			$	(4,993,173)
13	Update Non-fuel Base Revenue to 6/30/17 - ALJ 108			$	505,152	$	505,152
14	Pro Forma Revenue Adjustment - ALJ 109	$	-	$	2,707,619	$	2,707,619
15	Ad Valorem Taxes - Update to 6/30/17 - ALJ 98	$	(49,673)	$	-	$	(49,673)
16	Add Return of NE4 Regulatory Asset - ALJ 56	$	-	$	3,543,809	$	3,543,809
	Total Adjustments to operating income	$	**(60,565,830)**	$	**6,756,580**	$	**(53,809,250)**

Public Service Company of Oklahoma
ALJ'S Pro Forma Calculation of Taxable Income
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Amount	(B) ALJ Test Year Adjustment	(C) ALJ Total Company Pro Forma Amount	(D) Allocation Factor	(E) Oklahoma Jurisdictional Amount
1	Operating income before taxes	$ 257,323,776	$ 60,234,792	$ 317,558,568		$ 229,111,612
2	Interest-Long Term	$ 59,901,099	$ (2,086,096)	$ 57,815,003		$ 57,815,003
	Permanent Differences:					
3	50% Meal & Enter. Disallowance	$ 441,217	$ -	$ 441,217		$ 441,217
4	Book Depr. On Flo Thru Basis Diff	$ 2,844,000	$ -	$ 2,844,000		$ 2,844,000
5	SFAS 106 Post Retire Ben Medicare Subsidy	$ -	$ -	$ -		$ -
6	BIP AFUDC EQ. Amort	$ -	$ -	$ -		$ -
7	Preferred Dividend Credit	$ -	$ -	$ -		$ -
8	Manufacturing Deduction	$ -	$ -	$ -		$ -
9	Other	$ -	$ -	$ -		$ -
		$ -	$ -	$ -		$ -
10	Total Permanent Differences	$ 3,285,217	$ -	$ 3,285,217		$ 3,285,217
11	Book Taxable Income	$ 200,707,894	$ 62,320,888	$ 263,028,782		$ 174,581,826
12	Total Income Tax at Combined Rate of 38.6792014% 1.63076803	$ 77,632,208	$ 24,105,221	$ 101,737,429		$ 67,526,854
13	Other Differences:					
	Reversal of Reg Asset/Liab Excess ADIT	$ (672,000)	$ -	$ (672,000)		$ (672,000)
14	Amort of Def ITC - Federal	$ (2,066,383)	$ -	$ (2,066,383)		$ (2,066,383)
15	Amort of Def ITC - State	$ (82,408)	$ -	$ (82,408)		$ (82,408)
16	Def FIT on Def ITC - State	$ 28,843	$ -	$ 28,843		$ 28,843
17	Prior Period Adjustments	$ -	$ -	$ -		$ -
18	Total Other Differences	$ (2,791,948)	$ -	$ (2,791,948)		$ (2,791,948)
19	Total Federal and State Current and Deferred Income Taxes	$ 74,840,260	$ 24,105,221	$ 98,945,481		$ 64,734,906

Public Service Company of Oklahoma
Interest Synchronization Calculation
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description		(A) ALJ Total Company Pro Forma
1	Rate Base (Sec B, Schedule 1)	$	2,440,996,529
2	Weighted Cost of Debt (Sec F, Schedule 1)		2.3685%
3	Interest On Debt	$	57,815,003
4	Adjusted Interest on Debt	$	57,815,003

Public Service Company of Oklahoma
Adjustments to Current Income Tax Expense
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Adjustment Description	(A) Increase	(B) Decrease
	ALJ Adjustment No. 1		
1	To adjust Current Income Tax Expense for ALJ's Pro Forma Interest Expense	$ (2,086,096)	