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 201500208** **ORDER NO. 657877**

HEARING: August 24, 2016, Hearing on Exceptions to the Report and Supplemental Report of the Administrative Law Judge before the Commission

APPEARANCES:
Jack P. Fite, and Joann S. Worthington, Attorneys representing Public Service Company of Oklahoma
Judith L. Johnson, Deputy General Counsel, Natasha M. Scott, Deputy General Counsel, and Patrick M. Ahern, Assistant General Counsel, representing Public Utility Division, Oklahoma Corporation Commission
Dara M. Derryberry, Assistant Attorney General, representing Office of the Attorney General, State of Oklahoma
Thomas P. Schroedter and Jennifer H. Castillo, Attorneys representing Oklahoma Industrial Energy Consumers
Lee W. Paden, Attorney representing Quality of Service Coalition
Rick D. Chamberlain, Attorney representing Wal-Mart Stores East, LP and Sam's East, Inc.
Marc Edwards and Jim Roth, Attorneys representing Oklahoma Hospital Association
Marc Edwards and Jim Roth, Attorneys representing The Alliance for Solar Choice
Deborah R. Thompson, Attorney representing AARP
Matthew Dunne, General Attorney, representing U.S. 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 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 found in the Report and Recommendations of the Administrative Law Judge filed May 31, 2016 ("ALJ Initial Report").

The following events occurred since the filing of the ALJ Report.

On June 14, 2016, the Public Utility Division ("PUD"), PSO, the Oklahoma Attorney General ("AG"), and Oklahoma Industrial Energy Consumers ("OIEC") filed Exceptions to the ALJ Initial Report and filed motions for oral argument.

On June 14, 2016, PSO also filed a Motion for Remand, requesting that this matter be remanded to the ALJ to clarify and correct portions of the ALJ Initial Report.

On June 21, 2016, PUD filed a Response to PSO's Exceptions to the ALJ Initial Report; OIEC filed a Response to the Exceptions of PSO, the AG, and PUD to the ALJ Initial Report; PSO filed a Response to the Exceptions filed by the AG and OIEC to the ALJ Initial Report; and the United States Department of Defense and all other Federal Executive Agencies ("DOD/FEA") filed a Response to the Exceptions of PSO, PUD, the AG and OIEC to the ALJ Initial Report.

On June 29, 2016, the AG filed the Notice of Withdrawal of counsel C. Eric Davis.

On July 1, 2016, the Commission issued Order No. 653915, remanding this matter to the ALJ to provide the ALJ with the opportunity to review and consider assertions made in PSO's Motion to Remand and in the Exceptions filed by the various parties, and to issue a supplemental report. Order No. 653915 further directed the ALJ to submit an updated accounting exhibit.

On August 8, 2016, the ALJ filed a Supplemental Report Response ("ALJ Supplemental Report").

On August 8, 2016, a Notice of Withdrawal of Thad Culley as Counsel of record for The Alliance for Solar Choice was filed.

On August 10, 2016, PUD filed a Response to the Requests for Clarification of PUD Adjustments Addressed in the ALJ Supplemental Report.

On August 16, 2016, PSO, the AG, and OIEC filed Exceptions to the ALJ Supplemental Report.

On August 19, 2016, PSO and DOD/FEA filed Responses to the AG's and OIEC's Exceptions to the ALJ Supplemental Report.

On August 19, 2016, OIEC filed a Response to PSO's Exceptions to the ALJ Supplemental Report.

A hearing on the various exceptions to the Initial and Supplemental ALJ Reports was held before the Commission on August 24, 2016, and the matter was taken under advisement.

On September 2, 2016, the ALJ submitted an updated accounting exhibit.

On September 16, 2016, OIEC filed Supplemental Exceptions, excepting to the ALJ's updated accounting exhibit, and the DOD/FEA concurred in OIEC's exceptions.

On September 26, 2016, the AG filed exceptions to the ALJ's accounting exhibit and supplemental report response.

On September 20, 2016, the Quality of Service Coalition filed a Response in Support of OIEC's and the AG's September 16, 2016 supplemental exceptions to the ALJ's accounting exhibit.

On September 23, 2016, Public Service Company of Oklahoma filed a Reply to OIEC's Supplemental Exceptions to the ALJ's updated accounting exhibit and a Reply to the Attorney General's Exceptions to the ALJ's Accounting Exhibit.

On September 29, 2016, Jennifer Castillo filed a Notice of Withdrawal as Counsel of record representing OIEC.

II. SUMMARY OF EVIDENCE

The summary of evidence is found in the ALJ Initial Report.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

THE COMMISSION FINDS that it has jurisdiction over this matter by virtue of Article IX, Section 18, of the Oklahoma Constitution, 17 O.S. §§ 151 *et seq.*, and the rules and regulations 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.

After review of the ALJ Initial Report, ALJ Supplemental Report, hearing the arguments of counsel, and review and evaluation of the pleadings, exceptions, responses, and evidence contained in the record for this cause, and upon a full and final consideration thereof, the Commission hereby adopts the recommendations set forth in the ALJ Initial Report issued on May 31, 2016, except as otherwise stated herein.

Environmental Compliance Plan (ALJ Initial Report at Pages 148 and 149)

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 investments 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 investment in Northeastern Unit 2 to the extent that such investments are in service as of July 31, 2015.

The Commission rejects the ALJ's recommendation that PSO should be required to seek approval of three purchased power agreements related to replacement power for the retired Northeastern Unit 4 facility and instead finds that such purchased power agreements shall be examined for appropriateness of cost recovery in a PUD proceeding reviewing PSO's fuel adjustment clause.

The Commission rejects the recommendations made by the ALJ in the second full paragraph of page 149 of the ALJ Initial Report.

Cost of Capital (ALJ Initial Report at Page 150)

The Commission adopts a cost of equity of 9.50 percent, instead of the 9.25 percent recommended by the ALJ. The Commission finds that a cost of equity of 9.50 percent is within the range of return on equity recommended by OIEC witness Dave Parcell and DOD/FEA witness Reno. The Commission adopts the ALJ's recommendations of a cost of debt of 4.92 percent and a capital structure consisting of 56 percent debt and 44 percent equity. The Commission adopts an overall weighted average cost of capital of 6.9352 percent. The Commission finds that these cost of capital items are fair, just, and reasonable to both ratepayers and PSO. The Commission further finds that the ALJ's recommendation of an $8,152,488 adjustment to reduce pro forma incentive compensation expense is not a cost of capital item.

The Commission finds that PSO failed to provide persuasive evidence to support the increase in the allowed ROE sought by PSO. Mr. Hevert's recommended ROE of 10.25%-10.75% is excessive as Mr. Hevert's constant growth DCF results were based on unsustainable long-term growth rates. Mr. Hevert's testimony in this proceeding significantly overstates PSO's cost of equity. The Commission finds that each of Mr. Hevert's methods and his inputs into those methods are systematically biased upward in a manner that significantly inflates his cost of equity conclusions.

The Commission finds that an allowed ROE of 9.50 percent represents a conservative estimate of a fair and reasonable ROE for PSO. The Commission finds that this result best represents the opportunity cost of capital that an investor expects under today's financial and economic circumstances and also is in-line with recent Commission-approved returns in other jurisdictions.

The Commission finds that PSO's proposed hypothetical capital structure of 52 percent debt and 48 percent equity is not based on test-year capital amounts. While the Company seeks a hypothetical capital structure based on the premise that the Company may temporarily, and at some future time, withhold dividends to its parent company, AEP, the Commission finds that granting a hypothetical capital structure based on that premise is not a reasonable basis for setting the ratemaking capital structure in this case. Accordingly, the Commission adopts the ALJ's recommendation of a 56 percent debt and 44 percent equity capital structure.

Depreciation (ALJ Initial Report at Pages 150 and 163-166)

The Commission adopts the findings of the ALJ beginning with the fourth full paragraph on page 163 of the ALJ Initial Report, through the first two paragraphs of page 166 of the ALJ Initial Report regarding depreciation. Specifically, the Commission adopts the distribution plant depreciation rates recommended by PUD Witness David Garrett and the production plant and transmission plant depreciation rates recommended by OIEC Witness Jack Pous. With respect to general plant, the Commission adopts the recommendations of David Garrett for life spans for salvage value.

The Commission rejects the ALJ's findings at page 150 of the ALJ Initial Report under the heading, "Rate of Depreciation," as such findings are inconsistent with the ALJ's recommendations regarding depreciation at pages 163 to 166 of the ALJ Initial Report. The Commission adopts the revised depreciation expense adjustment calculation based on the findings set forth above as shown on the attached Final Order Accounting Schedule.

The Commission rejects the ALJ's recommendation in the fourth full paragraph on page 164 of the ALJ Initial Report.

Customer Deposits (ALJ Initial Report at Page 152)

The Commission adopts the recommendation of the ALJ accepting PUD's adjustments to decrease the customer deposit accounts but finds that such accounts should be decreased by $41,601 instead of the amount listed in the ALJ Initial Report.

AMI (ALJ Initial Report at Pages 153 and 156)

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.

Accumulated Deferred Income Tax (ALJ Initial Report at Page 154)

The Commission adopts the recommendation of the ALJ accepting PUD's adjustments to update accumulated deferred income tax to the 6-month post test year balance at July 31, 2015, but finds that such accounts should be decreased by $29,040,789 instead of the amount listed in the ALJ Initial Report.

Environmental Controls (ALJ Initial Report at Page 154)

The Commission rejects the ALJ's recommendation that $135,075,111 in environmental control investments be included in rate base for the reason that such investments were not in service and used and useful by the end of six months following test-year. Further, the ALJ's recommendation in this regard is inconsistent with the ALJ's other recommendations in the ALJ Initial Report that investments not in service by the end of six months following test-year end should not be included in rate base. The evidence in this case did not warrant any exception to the Commission's prior decisions that only those investments in service within six months of test year end should be included in rate base.

Cost of Service and Rate Design (ALJ Initial Report at Pages 155 and 156)

The Commission does not adopt the ALJ's recommendations regarding revenue distribution as the ALJ's recommendation is not applicable to the revenue requirement that results from this Order. Instead, the Commission adopts the revenue distribution recommendation of PUD witness Schwartz contained in his Responsive testimony which provides that PSO's customer classes should move closer to their actual cost of service. The Commission authorizes implementation of Mr. Schwartz's recommendation through an appropriate application of his rate design recommendation to the revenue requirement resulting from the findings made in this Order. The Commission finds that PUD witness Schwartz's revenue distribution proposal shall be applied to the revenue requirement determined in this Order in a manner consistent with the recommendation set forth in Mr. Schwartz's Responsive Testimony. The attached Final Order Revenue Distribution reflects the findings set forth above.

Transmission Allocation (ALJ Initial Report at Page 156)

The Commission does not adopt the ALJ's recommendation that a 12 coincident peak (12CP) method to allocate PSO's transmission costs be used. Instead, the Commission finds that a 4CP method is appropriate for transmission cost allocation. The Commission finds that PSO's system is a summer peaking system, and that it is appropriate to reflect the cost to use the transmission system during the four peak periods of the year, rather than all twelve months.

Fuel Adjustment Clause Rider (ALJ Initial Report at Page 157)

The Commission does not adopt the ALJ's recommendation that PSO should not modify its fuel adjustment clause to recover non-fuel consumable material costs for certain air quality control systems that PSO plans to install in the future. The Commission finds that environmental consumables are used in the generation of electrical energy and that their consumption rates are variable and highly correlated to the amount of fuel consumed and electrical generation produced. The Commission finds that PSO produced evidence supporting the need for recovery of consumable costs through the FAC as opposed to recovery through rates. The Commission, therefore, adopts PSO's request to modify its fuel adjustment clause to recover non-fuel consumable material costs.

Recovery of Northeastern Unit 4 Plant Costs (ALJ Initial Report at Pages 163, 166 and 167)

The Commission rejects the ALJ's recommendations regarding the suspension of recovery of the return on the Northeastern No. 4 Unit and the reduction in related O&M expenses. The Commission finds that since Northeastern Unit 4 will not be taken out of service until April 2016, which is outside of the six-month post test-year end period, it is premature for the Commission to rule on the recovery of stranded costs of the Northeastern No. 4 Unit. 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.

Revenue Normalization (ALJ Initial Report at Pages 167 and 168)

The Commission rejects the ALJ's recommendations denying normalization and updating of revenues for the reason that updating revenues to the six-month post-test year period is consistent with PSO's updating of expenses to the six month post-test year period and is also consistent with Oklahoma law, 17 O.S. § 284. The Commission adopts the recommendations of the AG and OIEC to recognize the increase in revenues that occurred within the six-month, post-test year period. The Commission finds that PSO's test year adjusted base rate revenues, net of fuel, should be increased to reflect updated customer accounts as of July 31, 2015. The attached Final Order Accounting Schedule reflects the adjusted base rate revenue amount, net of fuel, in accordance with the findings set forth above.

SPP Integrated Market ("IM") Revenues (ALJ Report at Pages 168 & 169)

The Commission rejects the ALJ's recommendation approving the current sharing mechanism of SPP IM revenues between PSO ratepayers and shareholders and instead, finds that PSO's FCA Rider should be modified to provide for PSO's retention of 10 percent of the Oklahoma retail jurisdiction share of off-system sales ("OSS") margins, rather than PSO's retention of 25 percent of such margins.

PSO's FCA Rider currently provides for the Company's retention of 25 percent of the Oklahoma retail jurisdiction share of OSS margins. Although the FCA Rider does not explicitly define off-system sales margins, PSO has included the net costs and revenues from a number of SPP IM market services it has purchased and sold as "off-system sales margins" and has retained 25 percent of such amounts for the Company and its shareholders. The net revenues at issue involve a number of SPP IM services, including regulation, spinning reserves, supplemental reserves services. (See Testimony of OIEC Witness Scott Norwood). The SPP integrated market place recently became effective (March 1, 2014) and the margins in question are attributable to SPP IM integrated marketplace revenues.

The Commission finds that PSO received approximately $7.3 million of net revenues from the purchase and sale of SPP IM services over the last 10 months of 2014 that the market was in effect. (See Norwood Exhibit SN-R4). The Company proposes to retain approximately $1.5 million of the total SPP IM net revenues it earned in 2014.

The Commission notes that OG&E's Fuel Adjustment Clause rider, authorized by the Commission, provides that OG&E does not share in any of the net profits of OSS. (Hearing Exhibit 47) Likewise, Empire District Electric Company's fuel adjustment clause tariff does not provide for the utility to share in OSS. (Hearing Exhibit 48).

PSO's customers pay the costs of operating the generating plants and the costs and charges incurred by PSO's employees who work on SPP integrated market place matters. Therefore, the Commission finds that it is appropriate to reduce PSO's share of OSS margins to ensure that ratepayers receive the bulk of those margins.

The Commission finds that PSO's FAC rider, Hearing Exhibit 46, shall be modified to provide that PSO receive 10 percent of the Oklahoma retail jurisdiction share of OSS margins while PSO ratepayers receive 90 percent of such margins.

Interim Rate Refund

The Commission finds that on January 15, 2016, PSO implemented an interim rate adjustment applicable to the base rate charges of all of PSO's retail customers. The Commission further finds that PSO's interim rate adjustment was implemented subject to refund. The Commission finds that a refund to customers of PSO's interim rate adjustment is appropriate and necessary to the extent it exceeds the rates approved by this Final Order. The Commission orders that the refund shall include reasonable interest at the one-year U.S. Treasury Bill rate consistent with 17 O.S. § 152, and shall be credited to PSO's customers using the same allocation method by which the interim rates were collected. The refund shall appear as a credit on customers' monthly billing and shall be refunded in equal monthly installments beginning with the first monthly billing cycle following this Order and concluding with the October 2017 monthly billing cycle. PSO shall submit a report monthly with the Director of the Public Utility Division reflecting the refund ordered herein.

ORDER

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION OF OKLAHOMA that the ALJ Initial Report attached hereto as Appendix A, subject to and as amended or superseded by the exceptions and 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 five (5) business 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.

IT IS SO ORDERED.

OKLAHOMA CORPORATION COMMISSION

Bob Anthony
BOB ANTHONY, Chairman

Dana L. Murphy
DANA L. MURPHY, Vice Chairman

DISSENT
J. TODD HIETT, Commissioner

DONE AND PERFORMED this 10th day of November, 2016.

BY ORDER OF THE COMMISSION:

Peggy Mitchell
PEGGY MITCHELL, Secretary

Final Order Accounting Schedule PSO
Final Order Revenue Requirement
Test Year Ended January 31, 2015
Cause No. PUD 201500208

Line No.	Description	(A) PSO Total Company Pro Forma Amount	Reference	(B) Final Order Total Company Adjusted Amount
1	Pro Forma Rate Base	$ 2,067,248,141	B-1	$ 2,024,773,269
2	Rate of Return	7.600%	F-1	6.9352%
3	Operating Income Required	$ 157,110,859	1 times 2	$ 140,422,076
4	Pro Forma Operating Income	$ 105,926,716	H-1	$ 182,953,631
5	Difference	$ 51,184,143	3 minus 4	$ (42,531,555)
6	Revenue Conversion Factor	1.637786		1.630768
7	**PSO Pro Forma Base Rate Revenue Increase/(Decrease)**	**$ 83,828,673**	5 times 6	(69,359,099)
8	**Final Order Proposed Change to PSO Pro Forma Base Rate Revenue Increase/(Decrease)**		5 times 6	**$ (69,359,099)**
9	**Final Order Pro Forma Base Rate Revenue Increase/(Decrease)**		7 minus 8	**$ 14,469,574**
10	Rev Inc Minus Difference	$ 32,644,530		$ (26,827,544)
	Revenue Requirement			
11	Return Requirement	$ 157,110,859	Line 3	$ 140,422,076
12	Total Operating Expense	$ 466,565,980	H-1	$ 451,318,441
13	Income Taxes	$ 62,988,656		$ 50,657,309
14	**Revenue Requirement**	$ 686,665,495	Line 8+9+10	$ 642,397,826

Final Order Accounting Schedule PSO
Explanation of Final Order Adjustments to Rate Base
Test Year Ended January 31, 2015
Cause No. PUD 201500208

Final Order Adj. No.	Adjustment Description	(A) Increase	(B) Impact On Rate Base Decrease	(C) Net Incr/(Decr)
1	To adjust Customer Deposits - Hogan		$ (41,601)	
2	Materials and Supplies - Hogan		$ (182,869)	
3	To adjust Plant in Service to 7/31/15 Balances - Thompson	$ 9,557,979		
4	To adjust Accumulated Depreciation to 7/31/15 Balances - Thompson		$ (39,145,204)	
5	Off System Trading Deposits	$ 876,539		
6	To adjust Accumulated Deferred Income Taxes - Thompson		$ (29,040,789)	
7	Thompson	$ 478,744		
8	Prepayments - Hogan		$ (1,709,670)	
9	Regulatory Asset for Non-Ami Meters - Thompson	$ 18,262,961		
ALJ 1	Reg Liabilities and Deferred Credits ALJ Report Page 148		$ (1,530,962)	
	Total Rate Base Adjustments	**$ 29,176,223**	**$ (71,651,095)**	**$ (42,474,872)**

Final Order Accounting Schedule PSO
Final Order Capital Structure
Test Year Ended January 31, 2015
Cause No. PUD 201500208

Line No.	Description	(A) PSO Capitalization Ratios	(B) PSO Cost of Capital	(C) PSO Weighted Cost of Capital
	PSO Requested Capital Structure:			
1	Long Term Debt	52.00%	4.92%	2.56%
2	Preferred Stock	0.00%	0.00%	0.00%
3	Common Stock	48.00%	**10.50%**	5.04%
4	Total	100.00%		7.60%

Line No.	Description	Final Order Capitalization Ratios	Final Order Cost of Capital	Final Order Weighted Cost of Capital
	Final Ordered Capital Structure:			
1	Long Term Debt	56.00%	4.92%	2.75520%
2	Preferred Stock	0.00%	0.00%	0.00%
3	Common Stock	44.00%	**9.50%**	4.180000%
4	Total	100.00%		6.935200%

Final Order Accounting Schedule PSO
Explanation of Final Order Adjustments to Operating Income
Test Year Ended January 31, 2015
Cause No. PUD 201500208

			(A)		(B)		
Final Order Adj.			IMPACT ON REVENUE REQUIREMENT				
No.	Adjustment Description		Decrease		Increase		Net Incr/(Decr)
1	To adjust Annual Incentives - Garrett	$	(8,152,488)				
2	To adjust Depreciation Expense - Garrett	$	(27,398,407)				
3	Amortization of Non-AMI Meters - Thompson			$	1,749,592		
4	To adjust Ad Valorem Taxes - Thompson	$	(2,133,195)				
5	To adjust Factoring Expense - Thompson	$	(297,186)				
6	Payroll Adjustment - Rush	$	(1,500,134)				
7	Payroll Tax Adjustment - Rush	$	(104,334)				
8	Rate Case Expenses Patel	$	(131,493)				
9	To include vegatation management revenues in base rate revenues And to include Vegatation management expenses in operating expenses - Champion	$	(21,374,304)	$	21,725,896		
10	Miscellaneous Sales Expense - Patel	$	(183,241)				
11	Rate Case expenses related to Expert Witness Costs - Patel			$	555,601		
ALJ 1	SERP Adj Page 162 of ALJ Report		(468,192)				
ALJ 2	Employee Medical Expenses		(864,257)				
AG Exceptions	Revenue Normalization 6-month post test			$	3,717,125		
PSO - Knight	Northeastern 4 O&M			$	1,954,299		
	Total Adjustments to operating income	**$**	**(62,607,231)**	**$**	**29,702,513**	**$**	**(32,904,718)**

Final Order Revenue Distribution PSO
Final Order Revenue Requirement
Test Year Ended January 31, 2015
Cause No. PUD 201500208

Customer Group	Proposed Class Increase	SRR Revenue	Miscellaneous Revenue	Special Contract	Total Impact
Residential					
LURS	$129,334	$ 57,673.05	$104,062	$16,302	($48,702)
RS	$32,215,795	$ 12,000,622.51	$3,784,843	$2,043,115	$14,387,214
RS TOD	$54,682	$ 25,471.48	$6,378	$3,415	$19,417
Total RS	**$32,399,811**	**$ 12,083,767.04**	**$3,895,283**	**$2,062,832**	**$14,357,930**
Commercial					
LUGS	$260,746	$ 1,840,327.56	$501,135	$393,973	($2,474,690)
GS	$5,573,427	$ 4,470,808.46	$78,224	$701,419	$322,976
PL	$2,187,571	$ 1,579,352.84	$12,673	$275,618	$319,927
Primary ND	$50,246	$ 50,017.94	$200	$7,289	($7,262)
MS	$2,369	$ 7,105.10	$18,951	$3,580	($27,268)
MP	$1,455	$ 15,619.39	$550	$2,199	($16,914)
Commercial Total	**$8,075,814**	**$ 7,963,231.29**	**$611,733**	**$1,384,080**	**($1,883,230)**
Lighting					
GSL	$1,205	$ 526.71	$0	$111	$567
OL	$53,175	$ 32,706.06	$0	$4,879	$15,589
SL / NR	$724,057	$ 106,619.90	$0	$66,426	$551,011
MSL	$131,355	$ 78,883.71	$0	$12,050	$40,421
TS	$4,848	$ 1,255.50	$0	$445	$3,147
Total Lighting	**$914,640**	**$ 219,991.88**	**$0**	**$83,912**	**$610,736**
Industrial					
LPL 3 Total	$2,257,041	$ 1,451,093.55	$3,360	$294,146	$508,441
LPL 2 Total	$839,162	$ -	$459	$253,619	$585,084
LPL 1 Total	$305,232	$ -	$192	$52,377	$252,663
Total Industrial	**3,401,435**	**$ 1,451,093.55**	**$4,011**	**$600,143**	**$1,346,188**
Total Retail	**$44,791,700**	**$ 21,718,083.76**	**$4,511,027**	**$4,130,966**	**$14,431,623**

$ 14,469,574 Accounting Proposed Increase
$ 37,951 Difference

APPENDIX A

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 201500208

FILED
MAY 31 2016
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

HEARING: December 8, 2015, in Courtroom 301
2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105
Before Jacqueline T. Miller, Administrative Law Judge

APPEARANCES: Jack P. Fite, Joann T. Stevenson, Donald K. Shandy, Kendall W. Parrish and Gerardo Noel Huerta. Attorneys *representing* Public Service Company of Oklahoma
Judith L. Johnson, Deputy General Counsel, Natasha M. Scott, Deputy General Counsel, and Patrick M. Ahern, Assistant General Counsel *representing* Public Utility Division, Oklahoma Corporation Commission
Jerry J. Sanger, Abby Dillsaver, Eric Davis and Dara M. Derryberry, Assistant Attorneys General, *representing* Office of the Attorney General, State of Oklahoma
Thomas P. Schroedter and Jennifer H. Castillo, Attorneys *representing* Oklahoma Industrial Energy Consumers
Lee W. Paden, Attorney *representing* Quality of Service Coalition
Rick D. Chamberlain, Attorney *representing* Wal-Mart Stores East, LP Sam's East, Inc.
Jim A. Roth, Marc Edwards, William L. Humes and Dominic D. Williams, Attorneys *representing* Oklahoma Hospital Association;
Jim A. Roth, William L. Humes, Dominic D. Williams, and Thad Culley, Attorneys, *representing* Alliance for Solar Choice
Deborah R. Thompson, Attorney *representing* AARP
Matthew Dunne, General Attorney, and James T. Forrest, Chief, *representing* Counsel for U.S. Department of Defense and all Other Federal Executive Agencies

REPORT AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE

The filing of this cause by Public Service Company of Oklahoma ("PSO") was made 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.

SUMMARY OF REPORT AND RECOMMENDATION

The ALJ's report and recommendations are set forth herein.

I. Procedural History

On May 14, 2015, Public Service Company of Oklahoma ("PSO" or "Company") filed its Notice of Intent, giving notice to the Oklahoma Corporation Commission ("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. During the pendency of this Cause, this Cause was transferred to the current Administrative Law Judge from the originally assigned Administrative Law Judge.

On May 19, 2015, the Attorney General ("AG") of the State of Oklahoma filed his Entry of Appearance.

On May 20, 2015, PSO filed an Entry of Appearance for Mr. Donald K. Shandy.

On June 1, 2015, Oklahoma Industrial Energy Consumers ("OIEC") filed an Entry of Appearance.

On June 23, 2015, Quality of Service Coalition filed an Entry of Appearance.

On June 24, 2015, PSO filed an Entry of Appearance for Mr. Kendall W. Parrish.

Also on June 24, 2015, the Commission's Public Utility Division ("PUD") filed a Motion for Assessment of Costs, along with a Notice of Hearing that set PUD's Motion for Assessment of Costs for hearing on July 2, 2015. On July 2, 2015, PUD's Motion for Assessment of Costs was continued to July 9, 2015. On July 9, 2015, PUD's Motion for Assessment of Costs was heard and recommended.

On July 1, 2015, PSO filed its Application, along with its Application Package.

Also on July 1, 2015, PSO filed a Motion to Establish Procedural Schedule, along with a Notice of Hearing that set the Motion to Establish Procedural Schedule for hearing on July 9, 2015. On July 9, 2015, the Motion to Establish Procedural Schedule was continued by agreement of the parties to July 16, 2015. On July 16, 2015, the Motion to Establish Procedural Schedule was continued by agreement of the parties to July 23, 2015. On July 23, 2015, the Motion to Establish Procedural Schedule was heard and recommended with instructions.

Also on July 1, 2015, PSO filed the Direct Testimonies of Howard L. Ground, Charles D. Matthews, John O. Aaron, Steven F. Baker, Mark A. Becker, Andrew R. Carlin, Steven L. Fate, Brian J. Frantz, Randall W. Hamlett, Robert B. Hevert, Jennifer L. Jackson, Gary C. Knight, John J. Spanos, Rajagopalan Sundararajan, Thomas J. Meehan, Kevin J. Munson, K. Shawn Robinson, C. Richard Ross, David P. Sartin, and Richard G. Smead.

On July 15, 2015, PUD filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements.

On July 20, 2015, the AG filed a Motion for Assessment of Costs, along with a Notice of Hearing that set the AG's Motion for Assessment of Costs for hearing on July 30, 2015. On July 21, 2015, the AG filed an Amended Notice of Hearing that set the AG's Motion for

Assessment of Costs for hearing on July 23, 2015. On July 23, 2015, all parties waived notice and the AG's Motion for Assessment of Costs was heard and recommended with instructions.

On July 23, 2015, the Commission issued Order No. 643363, Order Granting Public Utility Division's Motion for Assessment of Costs.

On August 11, 2015, PSO filed a Motion to Associate Counsel, along with a Notice of Hearing that set PSO's Motion to Associate Counsel for hearing on August 20, 2015. On August 20, 2015, PSO's Motion to Associate Counsel was heard and recommended with instructions.

On August 12, 2015, the Alliance for Solar Choice ("TASC") filed an Entry of Appearance.

Also on August 12, 2015, the Commission issued Order No. 644100, Order Granting Attorney General's Motion for Assessment of Costs.

Also on August 12, 2015, TASC filed a Motion to Associate Counsel.

On August 13, 2015, Oklahoma Hospital Association ("OHA") filed an Entry of Appearance.

Also on August 13, 2014, PSO filed the Addition to Exhibit MAB-1 of Mr. Mark A. Becker's Direct Testimony Filed July 1, 2015.

On August 18, 2015, the Commission issued Order No. 644241, Order Establishing Procedural Schedule. The order set the Hearing on the Merits for December 8, 2015.

On August 19, 2015, PSO filed a Motion to Determine Notice, along with a Notice of Hearing that set the Motion to Determine Notice for hearing on August 27, 2015. On August 27, 2015, the Motion to Determine Notice was heard and recommended with instructions.

On August 20, 2015, TASC filed a Notice of Hearing that set the Motion to Associate Counsel for hearing on August 20, 2015.

Also on August 20, 2015, TASC filed a Notice of Hearing that set the Motion to Associate Counsel for hearing on August 27, 2015. On August 27, 2015, Alliance for Solar Choice's Motion to Associate Counsel was heard and recommended.

On August 25, 2015, PSO filed the Affidavit of Mr. Huerta.

Also on August 25, 2015, TASC filed its Attachment: Certificate of Compliance.

On August 26, 2015, the AG filed an Entry of Appearance for Ms. Abby Dillsaver.

On September 10, 2015, the United States Department of Defense and all other Federal Executive Agencies ("DOD/FEA") filed an Entry of Appearance.

Also on September 10, 2015, DOD/FEA filed a Motion to Associate Counsel, 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 Notice of Hearing that set DOD/FEA's Motion to Associate Counsel, 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 September 17, 2015. On September 17, 2015, DOD/FEA's Motion to Associate Counsel, 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.

On September 14, 2015, AARP filed an Entry of Appearance.

On September 16, 2015, the AG filed an Entry of Appearance for Mr. Eric Davis.

On September 22, 2015, the Commission issued Order No. 645378, Order Determining Notice.

On September 25, 2015, DOD/FEA filed a Certificate of Compliance.

On September 28, 2015, PSO filed its Errata to Schedule N.

On September 29, 2015, Quality of Service Coalition, Wal-Mart Stores East, LP and Sam's East, Inc., PUD, the AG, OIEC, OHA, TASC and DOD/FEA filed their respective Major Issues Lists.

Also on September 29, 2015, the Commission issued Order No. 645565, Order Granting Motion to Associate Counsel, and Order No. 645566, Order Granting Motion to Associate Counsel.

Also on September 29, 2015, PSO filed the Summaries of Direct Testimony of Mark A. Becker, John O. Aaron, Steven F. Baker, Andrew R. Carlin, Charles D. Matthews, Richard G. Smead, Randall W. Hamlett, Steven L. Fate, Brian J. Frantz, John J. Spanos, Thomas J. Meehan, Jennifer L. Jackson, K. Shawn Robinson, Robert B. Hevert, C. Richard Ross, Kevin J. Munson, Howard L. Ground, Rajagopalan Sundararajan, Gary C. Knight and David P. Sartin.

On October 8, 2015, the AG filed an Entry of Appearance for Ms. Dara M. Derryberry.

On October 12, 2015, Public Comment was filed.

On October 14, 2015, DOD/FEA filed the Testimony Summary of Lafayette K. Morgan, Jr., the Responsive Testimony of Lafayette K. Morgan, Jr., the Testimony Summary of Larry Blank, the Responsive Testimony of Larry Blank, the Testimony Summary of Maureen L. Reno, and the Responsive Testimony of Maureen L. Reno.

Also on October 14, 2015, Wal-Mart filed the Summary of the Responsive Revenue Requirements Testimony and Exhibits of Steve W. Chriss and the Responsive Revenue Requirement Testimony and Exhibits of Steve W. Chriss.

Also on October 14, 2015, PUD filed its Accounting Exhibit, as well as the Responsive Testimony of Robert C. Thompson, CPA, the Summary Testimony of Kathy Champion, the Summary Testimony of Robert C. Thompson, CPA, the Responsive Testimony of Jason C. Chaplin, the Responsive Testimony of Kathy Champion, the Responsive Testimony of Geoffrey M. Rush, the Summary Testimony of Jason Chaplin, the Summary Testimony of Geoffrey M. Rush, the Testimony Summary of David J. Garrett on Cost of Capital, the Testimony Summary of David J. Garrett on Rate of Depreciation, the Summary Testimony of Hunter Hogan, the Responsive Testimony of Hunter Hogan, the Responsive Testimony of Kiran Patel, the Summary Testimony of Kiran Patel, the Responsive Testimony of David J. Garrett on the Rate of Depreciation, the Testimony Summary of Dr. Craig Roach, the Responsive Testimony of David J. Garrett on Cost of Capital, and the Responsive Testimony of Craig Roach, Ph.D.

Also on October 14, 2015, the AG filed the Summary of Responsive Testimony of Bruce W. Walter, the Summary of Responsive Testimony of E. Cary Cook, the Summary of Responsive Testimony of J. Bertram Solomon, the Summary of Responsive Testimony of Paul J. Wielgus, the Summary of the Responsive Testimony of Edwin C. Farrar, the Responsive Testimony of J. Bertram Solomon, the Responsive Testimony and Exhibits of E. Cary Cook, the Responsive Testimony and Exhibits of Paul J. Wielgus, the Responsive Testimony and Exhibits of Bruce W. Walter and the Responsive Testimony of Edwin C. Farrar.

Also on October 14, 2015, OIEC and Wal-Mart filed the Testimony Summary of Jacob Pous, OIEC filed the Summary Testimony of David C. Parcell, the Testimony Summary of Scott Norwood, the Confidential Responsive Testimony of Scott Norwood, the Redacted Responsive Testimony of Scott Norwood, the Responsive Testimony of Mark E. Garrett and OIEC and Wal-Mart filed the Direct Testimony of Jacob Pous.

Also on October 14, 2015, OIEC and Wal-Mart Stores East LO and Sam's East, Inc. filed the Testimony Summary of Jacob Pous.

On October 15, 2015, PSO filed its Objection to Quality of Service Coalition's Fourth Set of Data Requests ("Objection"). The Objection was set for hearing on October 22, 2015. On October 22, 2015, PSO announced that it had filed its Withdrawal of Objection, and the ALJ recommended the withdrawal.

Also on October 15, 2015, OIEC filed the Summary Responsive Testimony of Mark E. Garrett.

On October 21, 2015, PSO filed its Withdrawal of Objection.

On October 23, 2015, DOD/FEA filed the Responsive Testimony Summary of Larry Blank on Rate Design/Cost of Service Issues and the Responsive Testimony of Larry Blank on Rate Design/Cost of Service Issues.

Also on October 23, 2015, the AG filed the Rate Design Responsive Testimony of Edwin C. Farrar, the Summary of Rate Design Responsive Testimony of Edwin C. Farrar, the Responsive Testimony of James W. Daniel and the Summary of the Responsive Testimony of James W. Daniel.

Also on October 23, 2015, OIEC filed the Summary Responsive Rate Design Testimony of Mark E. Garrett, the Responsive Rate Design Testimony of Mark E. Garrett, the Confidential Responsive Testimony of Scott Norwood, the Summary Responsive Rate Design Testimony of Scott Norwood and the Redacted Responsive Testimony of Scott Norwood.

Also on October 23, 2015, PUD filed the Cost of Service/Rate Design Responsive Testimony of Jeremy K. Schwartz and the Cost of Service/Rate Design Summary Responsive Testimony of Jeremy K. Schwartz.

Also on October 23, 2015, OHA filed the Summary of Responsive Testimony of John Athas and the Responsive Testimony of John Athas.

Also on October 23, 2015, Wal-Mart filed the Responsive Rate Design and Cost of Service Testimony and Exhibits of Steve W. Chriss and the Summary of the Responsive Rate Design and Cost of Service Testimony and Exhibits of Steve W. Chriss.

On October 27, 2015, Public Comment was filed.

Also on October 27, 2015, the Commission issued Order No. 646381, Order Granting Motion to Associate Counsel, For Temporary Admission, For Admission Upon Filing of Certificate of Compliance, And For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys.

Also on October 27, 2015, Quality of Service Coalition filed its Statement of Position.

On October 30, 2015, AARP filed its Statement of Position, and The Alliance for Solar Choice filed its Statement of Position.

On November 4, 2015, the Commission issued Order No. 646584, Order Granting Withdrawal of Objection.

On November 10, 2015, Public Comment was filed.

Also on November 10, 2015, PSO filed the Rebuttal Testimonies of David P. Sartin, Steven L. Fate, Mark A. Becker, Richard G. Smead, Randall W. Hamlett, John J. Spanos, Thomas J. Meehan, Robert B. Hevert, Brian J. Frantz, Andrew R. Carlin, Gary C. Knight, Steven F. Baker, C. Richard Ross, A. Naim Hakimi, John O. Aaron, and Jennifer L. Jackson.

Also on November 10, 2015, OIEC filed the Confidential Rebuttal Testimony of Scott Norwood, the Rebuttal Testimony of Mark E. Garrett, and the Redacted Rebuttal Testimony of Scott Norwood.

Also on November 10, 2015, the AG filed the Rebuttal Testimony of Edwin C. Farrar and the Rebuttal Testimony and Exhibits of Bruce W. Walter.

On November 16, 2015, PSO filed its Proof of Direct Notice and its Proof of Publication.

Also on November 16, 2015, TASC filed the Notice of Withdrawal as Counsel, withdrawing Mr. William L. Humes as counsel of record representing The Alliance for Solar Choice.

On November 24, 2015, OIEC filed the Rebuttal Testimony Summary of Scott Norwood and the Rebuttal Testimony Summary of Mark E. Garrett.

On November 25, 2015, PSO filed the Summary of Rebuttal Testimony of Jennifer L. Jackson, the Summary of the Rebuttal Testimony of Andrew R. Carlin, the Summary of the Rebuttal Testimony of Steven F. Baker, the Summary of the Rebuttal Testimony of Steven L. Fate, the Summary of the Rebuttal Testimony of Thomas J. Meehan, the Summary of the Rebuttal Testimony of David P. Sartin, the Summary of the Rebuttal Testimony of C. Richard Ross, the Summary of the Rebuttal Testimony of Richard G. Smead, the Summary of the Rebuttal Testimony of Robert B. Hevert, the Summary of the Rebuttal Testimony of Randall W. Hamlett, the Summary of the Rebuttal Testimony of John O. Aaron, the Summary of the Rebuttal Testimony of John J. Spanos, the Summary of the Rebuttal Testimony of Mark A. Becker, the Summary of the Rebuttal Testimony of Brian J. Frantz, the Summary of the Rebuttal Testimony of Gary C. Knight, and the Summary of the Rebuttal Testimony of A. Naim Hakimi.

On December 2, 2015, the AG filed the Summary of the Rebuttal Testimony of Bruce W. Walter and the Summary of the Rebuttal Testimony of Edwin C. Farrar.

On December 3, 2015, PSO filed its Exhibit List, Witness List, Issue Spreadsheet and Surrebuttal Testimony Issues, PUD filed its Exhibit List and its Surrebuttal Testimony Issues, OHA filed its Exhibit and Witness List, Quality of Service Coalition filed its Exhibit List, Wal-Mart filed its Witness and Exhibit List, the AG filed its Exhibit and Witness List and its Surrebuttal Issues List, OIEC files its Surrebuttal Issues List and its Exhibit and Witness List, TASC filed its Exhibit List, PUD filed its Amended Exhibit List, the DOD/FEA filed its Oral Sur-rebuttal Testimony Issues, its Exhibit List and its Witness List, and AARP filed its Exhibit and Witness List.

Also on December 3, 2015, PSO filed the Testimony of Mr. Steven J. Wooldridge Adopting the Testimony of Charles Matthews, and the Testimony of Mr. Perry M. Barton Adopting the Testimonies of Mr. Gary C. Knight.

On December 9, 2015, Public Comments were filed.

II. Summary of Evidence

Summaries of Direct Testimony of PSO

David P. Sartin

David P. Sartin, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO), an operating company subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Sartin testified that the primary reason for this base rate case is PSO's request for recovery of the costs associated with environmental compliance with the United States Environmental Protection Agency's (EPA) Regional Haze Rule (RHR) and Mercury and Air Toxics Standard (MATS) for Northeastern Units 3 and 4.

PSO's compliance with the RHR and MATS environmental requirements is being completed according to an Oklahoma State Implementation Plan (Oklahoma SIP),[1] adopted by the State of Oklahoma, and reviewed and approved by the EPA. Once approved by the EPA and subjected to public notice requirements, it is Mr. Sartin's understanding the Oklahoma SIP became enforceable as both Oklahoma and federal law.

Substantially, all of the framework for the Oklahoma SIP was provided in the agreement between the EPA, United States Department of Justice, Secretary of the Environment of the State of Oklahoma, Oklahoma Department of Environmental Quality, the Sierra Club, and PSO. Pursuant to the Oklahoma SIP, the compliance deadline for the RHR and MATS is April 16, 2016. PSO witness Ground describes the agreement in more detail.

PSO provides in this case the information and analysis it used in determining the reasonableness of the Oklahoma SIP as a basis for the OCC to approve the timing and method of recovery of the costs PSO is requesting be included in the rates charged to customers.

Mr. Sartin explained that PSO is requesting the OCC approve an annual increase in rates of $137 million. This request includes $61 million to recover the costs of environmental control investments and associated expenses directly related to PSO's ECP consistent with the Oklahoma SIP. In addition, the request includes a proposed $76 million base rate increase to recover cost increases since PSO's last base rate case that had a test year ending July 31, 2013.

Mr. Sartin described how PSO proposes to recover the requested costs through base rates and riders as set forth below (dollars in millions):

Cost Type	Recovery Mechanism	Amount
Environmental control investments—return, depreciation, and taxes	Environmental Compliance Rider (ECR) or Base Rates	$ 44
Environmental control consumables	Fuel Cost Adjustment Rider (FCA)	4
Northeastern Units 3 and 4 change in depreciation rates	Base Rates	13
Total Environmental[2]		61
Other base rate costs	Base Rates	76
Total requested change in rates		$137

[1] As explained in PSO witness Ground's testimony, an original Oklahoma SIP was partially approved by the EPA, and a revised Oklahoma SIP was adopted by the State of Oklahoma through the actions of the Secretary of the Environment of the State of Oklahoma and the Oklahoma Department of Environmental Quality.

Mr. Sartin further explained that although cost recovery is not sought in this case, there is $35 million in annual incremental purchased capacity and energy costs associated with the Northeastern Unit 4 retirement that will be recovered through the FCA beginning January 2016, and will be subject to the OCC's normal FCA process.

Mr. Sartin provided the total first full year impact (dollars in millions) on customers' rates as follows:

Cost Type	Recovery Mechanism	Amount
Total Requested Change in Rates	See Table Above	$137
Purchased Capacity and Energy	FCA	35
Total First Full Year Impact		$172

He also discussed PSO [*sic*] proposal that $128 million of the increase be included in customers' rates in the first billing cycle of January 2016, and the $44 million rate increase applicable to the environmental control investments be implemented with the first billing cycle of March 2016. The later date for the environmental controls will ensure the Northeastern Unit 3 controls are in service prior to rates going into effect. The controls being in service benefit customers because they are required to keep Northeastern Unit 3 operational consistent with environmental requirements discussed previously.

As to FCA changes in January 2016, Mr. Sartin explained that in addition to the annual purchased power and consumable changes provided above, the FCA will be adjusted for the actual amounts expected to be incurred during 2016 for these amounts, as well as other changes to the FCA unrelated to the ECP like the costs of wind, natural gas, coal, over-and under-recoveries, and other purchased power. This will include the impacts of the savings associated with new wind purchased power agreements discussed by PSO witness Fate.

Mr. Sartin explained why PSO's costs to provide electric service have increased from the cost of service in PSO's test year in the last base rate case. The primary changes are as follows (dollars in millions):

Category	Cost
Depreciation	$35
Operation and maintenance	28
Income taxes	8
Other taxes	(8)
Return and other	19
Revenues	(6)
Total	$76

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. The rates are proposed to increase largely in the areas of production and distribution because existing rates are not adequate to permit appropriate cost recovery.

Operation and maintenance expenses have increased largely from higher Southwest Power Pool transmission service, and higher costs in the generation, transmission, and distribution functions.

Income taxes have grown because of the tax effect of the return on a growing rate base. Property taxes have declined due to a reduced taxable base because of changed property tax law. Return and other [*sic*] increased 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 higher numbers of customers resulting in increased total kilowatt-hour sales.

He also provided that the total annual cost of environmental compliance is $99 million,[2] which includes the costs of the plan for Northeastern and Oklaunion coal units, natural gas units, and replacement purchased power.

The updated environmental total annual costs of $99 million in this cause are $65 million, or 40% lower than the prior estimate of $164 million.[3] The new costs are lower primarily due to reduced replacement power costs from lower natural gas prices, and lower environmental control investment costs. The impact on annual customers' bills for environmental compliance is 8%.

He advised the Commission that included in the $99 million is $5 million per year currently included in rates for compliance costs for the RHR NOx environmental controls installed on PSO's generating units.[4]

Although PSO's rates are expected to increase, PSO provides opportunities for customers to help mitigate the increase through better management of their electric usage such that electric costs may be lowered. PSO provides energy efficiency/demand reduction programs for residential and business customers that provide opportunities for customers to reduce electric bills by implementing cost savings activities like installing new windows, doors, and HVAC systems. Also, with the deployment of advanced metering infrastructure (AMI), PSO customers can take advantage of the additional information and tariffs made possible through this technology to change their electric usage patterns, and in particular to reduce usage during peak hours of the day to reduce their costs, and reduce PSO's costs to serve all customers.

Next, Mr. Sartin discussed that PSO's quality of service continues to improve as measured by electric service reliability, customer satisfaction, and low Commission complaints.

[2] PSO witness Hamlett, Exhibit RWH-1
[3] PSO witness Hamlett, Exhibit RWH-1, Cause No. PUD 201200054
[4] See Cause No. PUD 201300217, and PSO witness Hamlett Exhibit RWH-4. An additional $1.986 million of the Northeastern Unit 2 environmental controls are included in this current case.

In addition, employees work safely in providing this service as evidenced by PSO's employee safety performance, which ranks in the top quartile of industry safety standards.

Importantly, even with the proposed rate increase, PSO's rates continue to compare favorably to other electric utilities. According to information from the U.S. Energy Information Administration (EIA), PSO's total rates are 2%, 6%, and 22% below state of Oklahoma, regional, and national averages, respectively, after taking into account the proposed increase in this case. It is also important to note that virtually all electric utilities' rates - investor-owned, municipals, and cooperatives - either have been or will be increased as a result [*sic*] EPA compliance costs. Due to different compliance strategies and the timing of rate changes, not all of these increased costs would be reflected in EIA's data at this time. PSO's reasonable rates, coupled with its quality of customer service, indicate PSO's customers continue to receive value for the service provided by PSO.

Mr. Sartin discussed how PSO's plan was explained in Cause No. PUD 201200054[5], which was an application by PSO filed on April 26, 2012, for OCC authorization of a plan and cost recovery of actions of PSO to be in compliance with the EPA rules mentioned previously. PSO's plan included the construction of new environmental controls on Northeastern Unit 3 to be in service by April 2016, the retirement of the Northeastern Unit 4 coal unit in April 2016 and Unit 3 in December 2026, and the addition of new purchased power contracts to meet capacity and energy needs. In that Cause, PSO requested approval of its plan for capital expenditures for equipment and facilities to comply with EPA rules, and approval of cost recovery for its power purchase contract and the Independent Evaluator expense.

PSO further requested the OCC approve, for future depreciation studies and capital cost recovery, that all of the Northeastern Units 3 and 4 investment (including all emission control investment) be fully depreciated by 2026. And finally, PSO requested that the OCC approve the requested earnings on the purchased power contract.

Mr. Sartin discussed the four modifications to PSO's request as compared to the prior case. First, PSO no longer requests OCC authorization of an environmental compliance plan as the plan has now been finalized with the actions taken by the State of Oklahoma and the EPA. Second, PSO no longer requests approval for recovery of its purchased power contracts as conditions precedent in the contracts have been satisfied, and the costs will be included in the FCA. Third, PSO no longer requests approval of the previously incurred Independent Evaluator Expense [*sic*] as those were approved for recovery as a part of PSO's prior base rate case, Cause No. PUD 201300217. Fourth, PSO no longer seeks recovery of the requested earnings on the purchased power contract as this matter was addressed in Cause No. PUD 201200079.

Mr. Sartin further explained that, as a part of this base rate case, PSO was requesting OCC approval for:

1) cost recovery of the environmental controls completed and in service at the end of the test year;

[5] Since that filing, final compliance decisions have been made regarding Oklaunion Power Station as described in PSO witness Fate's direct testimony.

2) cost recovery of the investment in Northeastern Unit 3 environmental control equipment and facilities either through a rider or through base rates;
3) cost recovery of the Comanche Power Station environmental control equipment and facilities either through a rider or through base rates;
4) recovery through depreciation rates of the remaining undepreciated book value of Northeastern Units 3 and 4 by 2026, the year Northeastern Unit 3 will retire;
5) an amendment to the FCA to include air quality control system consumables; and
6) recovery of the Independent Evaluator expenses to be incurred in this case over a two-year period.

As to the environmental costs for Northeaster [*sic*] Unit 3 and Comanche, PSO proposed they be recovered, under either alternative, and would include depreciation, return, and property taxes. PSO proposed under either alternative that the actual investment in environmental controls at January 31, 2016, be included in rate base in this rate case.

According to Mr. Sartin, PSO witness Hamlett describes the determination of costs to be recovered under the ECR and under base rates. PSO witness Aaron discussed the ECR tariff. Under the ECR alternative, PSO has used the same approach it has used under a variety of existing riders that have been approved by the OCC, which includes true-ups to ensure cost recovery matches costs so that PSO customers are not paying more than actual costs.

For purposes of cost recovery under the base rate alternative in this case, Mr. Hamlett describes a similar process. Although similar, this approach differs somewhat from the ECR alternative in that it would use the actual investment costs of the Northeastern Unit 3 and Comanche environmental controls at January 31, 2016, as well as estimates of the Comanche costs to be incurred through its in service date in June 2016. Regulatory asset accounting would be used to accumulate the additional costs of the environmental controls not recovered in base rates in this case. Recovery of the regulatory asset would be determined in a subsequent proceeding.

PSO will cap the amount of environmental control investments used to determine cost recovery in this case for either the ECR, or base rates, at a total investment of $221 million.[6] Amounts above this level would be included in PSO's rate relief request in a subsequent base rate case.

Cost recovery under either alternative would begin with the first billing cycle in March 2016, the first month subsequent to the month the environmental controls are placed into service for Northeastern Unit 3. PSO would delay the effective date of new rates to the month following the month the Northeastern Unit 3 environmental controls are actually placed in service.

Also, to the extent the environmental control investment costs are higher than those used in determining the revenue deficiency in this case, no adjustment would be made to the rate relief requested in this case. Any such additional costs would be proposed for recovery in a subsequent base rate case. To the extent the costs are lower, PSO would adjust its rate relief request downward.

[6] Environmental control costs: Northeastern Unit 3—$178.6 million and Comanche—$42.6 million. See PSO witness Hamlett Exhibit RWH-1.

In the event the OCC determines that rider recovery is appropriate, PSO will file a subsequent base rate case, which will be after the final costs are incurred and known for the Northeastern Unit 3 and Comanche environmental controls. This will provide the Commission the opportunity to review the reasonableness of the costs incurred after January 31, 2016, and include them in rate base. The ECR would expire with the effective date of new base rates.

Mr. Sartin testified that PSO was not requesting approval of the environmental controls costs incurred after January 31, 2016. PSO will request the OCC to find as reasonable the costs incurred after January 31, 2016, when they are included in rate base in the next base rate case. Until then, there is no Commission approval.

Mr. Sartin testified that it was reasonable for the OCC to permit recovery of the environmental controls in this case even when they do not go into service until February 2016. PSO believed it was appropriate in this case to go beyond the OCC's traditional six-month post test year period in permitting cost recovery for a variety of reasons:

1) the Commission has stated it has the authority to go beyond six months;[7]

2) the compliance date for having new controls in effect was set by the Oklahoma SIP;

3) PSO's case has a traditional test year cost approach, with pro forma adjustments to include all of the effects of the ECP occurring beyond six months, including:

   a. Northeastern Unit 4 operation and maintenance expense reduction beginning in 2016.

   b. Northeastern Unit 4 coal pile reduction that begins in early 2016.

   c. environmental control consumables that begin in February 2016.

   d. incremental capacity and energy costs beginning in April and June 2016, and

   e. depreciation expense changes that begin in January and February 2016;

4) it reduces regulatory lag for a portion of PSO's environmental investments, but certainly does not eliminate all of PSO's regulatory lag because of the continued delay in getting new rates in effect to recover the other $300 million of plant additions since the last base rate case, and another $200 million plus PSO will invest the balance of 2015;

5) it fairly matches cost recovery with the in-service date of the environmental controls;

[7] The Commission has expressed its authority to make post-test year adjustments greater than six months. See Order No. 545168 issued in Cause No. PUD 200600285 at pages 122-127.

6) the over-and under-accounting proposed by PSO witness Hamlett ensures that customers only pay for the actual costs of the environmental controls;

7) Northeastern Unit 4 retires in April 2016 in accordance with the Oklahoma SIP;

8) as discussed below, there is no revenue growth associated with the Northeastern 3 environmental investment;

9) PSO has not previously requested construction work in progress in rate base for the environmental controls, so PSO has been incurring the carrying costs of these investments since construction began with no cash inflows from customers;

10) the matching of the revenues to the costs PSO incurs improves cash flows, which improves rating agency metrics in support of a continued good bond rating;

11) PSO has reduced its common stock dividends to improve cash flows and rebalance its capital structure; and

12) the additional wind capacity PSO has added will begin production in 2016, and its lower costs will help offset the proposed FCA increases.

Mr. Sartin pointed out that PSO's financial condition has declined while the environmental controls are under construction because it is financing the cash outflow for the construction of environmental controls through the issuance of additional debt and equity capital with no cash inflows from customers until the new controls are completed and in service.

There will be no retail sales growth as a result of the completion of the environmental controls, and there will be no increase in the level of off-system sales, both of which typically benefit both customers and PSO when new generation plant has historically been built and placed in service due to increased customer load.

As discussed by Mr. Sartin, under a traditional base rate case, when a new large electric utility investment goes in service there is a lag in the recovery of the costs incurred by PSO from the time the investment goes in service and the time new revenues are received to recover those costs. This means PSO would incur higher costs for a period for which it has no revenues. This lag period is at least five months, and it occurs because of the conventional, although not required, limitation for making post-test year adjustments to only 6 months, coupled with the time it takes to file and go through the various rate case phases.

In this base rate case, the annual revenue short-fall for the environmental controls is $44 million. A delay in cost recovery beyond March 2016 will prohibit PSO from the opportunity to earn a fair return on investment, despite the fact PSO has provided the funds to construct the asset. While PSO is never guaranteed that it will earn the authorized return, it is reasonable for the OCC to permit PSO the opportunity to earn its authorized return.

Additionally, Mr. Sartin explained there was no change in risk between the Company and customers because the Commission is approving the plant in rate base in either the base rate or the ECR recovery method. There is only a modest change in the timing of the process used by the OCC to determine the reasonableness of the costs to be charged customers. The OCC's authority and oversight over PSO's rates and service remains unchanged. The OCC continues to review and approve PSO's rates charged to customers for all rate base amounts, including the environmental controls. The only change to the process is that the OCC approves the rates to recover the environmental costs as of January 31, 2016. Costs incurred after that date are subject to a complete review and approval in a subsequent case.

Mr. Sartin also explained that, as result of the ECP, there is a loss of PSO earnings. This occurs first, with the retirement of the Northeastern Unit 4 in 2016, PSO chose to replace the needed capacity from this unit with a purchased power agreement from a third party via a competitive bidding process with OCC oversight. PSO made this selection rather than investing in a new power plant. Second, PSO's compliance plan avoided $650 million in environmental control investments compared to other options. Since PSO selected options with lower investments, it results in lower rate base, and lower earnings.

Mr. Sartin discussed the history of PSO's ECP, and how Commission approval was sought and explained fully in April 2012, in Cause No. PUD 201200054.

PSO filed Direct, Rebuttal and Surrebuttal Testimony. Intervenors and Staff filed Responsive, Rebuttal, and Surrebuttal Testimony. In addition, extensive discovery was conducted by parties. In essence, the case proceeded in a similar fashion as a base rate case, but did not proceed to a hearing since it was dismissed just prior to the scheduled hearing date. All of the parties' positions were clearly delineated through this process that occurred mostly in 2012, closer to the time PSO's management decision-making actually occurred.

Mr. Sartin provided a summary of the parties that filed testimony and their high-level positions:

1) PUD and the Oklahoma Attorney General (OAG), through the Independent Evaluator - PSO's ECP was reasonable and should be approved; recommended conditions and a revised cost recovery schedule.

2) Oklahoma Industrial Energy Consumers (OIEC) - Did not recommend approval of the ECP; believed that it was premature; did not support recovery of the costs of the Northeastern coal units to be retired; concluded that fully retrofitting both of the Northeastern coal units was a better option than the ECP.

3) The Sierra Club - The ECP was the most reasonable approach for complying with environmental laws.

4) Chesapeake Energy Corporation - Overall, the ECP was reasonable, and recommended approval.

The parties filing testimony in that cause determined that PSO's plan was reasonable, except for OIEC.

In Cause No. PUD 201200054, Dr. Craig R. Roach, President and Founder of Boston Pacific Company, Inc., conducted a review as an independent evaluator. Dr. Roach filed

Responsive Testimony on January 8, 2013; Rebuttal Testimony on February 11, 2013; and Surrebuttal Testimony on March 22, 2013. On page 1 of Dr. Roach's Testimony he stated, beginning on line 10:

> Boston Pacific has been hired to provide consulting and independent expert witness services to assist and represent Staff and the OAG in this proceeding. The views expressed herein are my own.

Dr. Roach explicitly recognized from his independent review of PSO's analysis of the alternatives available for PSO to comply with the RHR and MATS requirements that:

1) the EPA Settlement was a reasonable compromise (Responsive, page 6);

2) the costs of the EPA Settlement are reasonable (Responsive, page 8);

3) the EPA Settlement has the lowest reasonable, risk-adjusted cost (Responsive, page 12); and

4) the selection of the Calpine PPA bid was the lowest reasonable cost option (Responsive, page 54).

PSO did not agree with all of Dr. Roach's testimony. Specifically, PSO did not agree with Dr. Roach's recommendations (Responsive, pages 15 and 16) that:

1) the decision for cost recovery of the book value of Northeastern Unit 3 be delayed until a hearing in 2020;

2) the decision that incremental energy costs from the capacity factor reductions beginning in 2021 be delayed until 2020; and

3) the incremental energy costs from the retirement of Northeastern Unit 3 in 2026 not be determined until 2020.

According to Mr. Sartin, it appeared that one of the bases for Dr. Roach's recommendation to delay decisions until 2020 was that a hearing in 2020 would be "hopefully after much of the litigation on the relevant environmental regulations is resolved." (Responsive, page 15)

Mr. Sartin believed one of the significant legal proceedings he was referring to was where Oklahoma Gas and Electric Company (OG&E), with the OAG, and OIEC, challenged the EPA on the requirements of the RHR, which included appealing the Tenth Circuit Court of Appeals decision to the United States Supreme Court. It was his understanding that OG&E's petition for a Writ of Certiorari was denied in March 2014. He believed that would be the primary litigation that was in place when Dr. Roach made reference to litigation in his Responsive Testimony, and appeared to be one of the bases for his recommendation to delay decision-making for certain cost recovery items. Since the litigation has been resolved, it appeared that even if one believed it provided a reasonable basis for delaying a decision with respect to PSO's ECP, the basis for waiting no longer exists according to Mr. Sartin.

Dr. Roach, in Cause No. PUD 201200054, provided Rebuttal Testimony addressing the issues raised by OIEC, the Sierra Club, and Chesapeake. After considering their views, he confirmed his recommendation that the Commission approve cost recovery for the EPA Settlement, with some conditions (page 2).

Mr. Sartin's Rebuttal Testimony in the prior Cause indicated agreement with much of Dr. Roach's testimony and conclusions, and in particular that he found PSO's ECP was reasonable and should be approved by the OCC. He did take exception to Dr. Roach's recommendation to review a part of PSO's ECP based on information only available several years after implementation because that is inconsistent with sound regulatory policy. Mr. Sartin testified that based on his understanding of OAC 165:35-1-2, OCC and Federal Energy Regulatory Commission decisions, and other authorities, PSO's full ECP must be judged on the information available at the time PSO made the decision, and not on information available years later.

After reviewing the other parties' testimony in PUD NO. 201200054, Mr. Sartin concluded PSO's ECP and cost recovery proposal should be approved as requested because:

1) most importantly, it provided some reasonable certainty that PSO will have sufficient electricity for its customers in 2016;

2) it was supported by the Oklahoma Department of Environmental Quality and the Oklahoma Secretary of Environment;

3) it was a low-cost, reasonable plan (among the plausible alternative plans available to PSO);

4) it was the plan with the lowest year 1 customer rate impacts and lowest customer impacts during the next 12 years;

5) it allowed PSO to be in compliance with EPA emission requirements, which under anticipated deadlines, [*sic*] had the real possibility of jeopardizing PSO's ability to adequately supply electricity to its customers in 2016;

6) while other parties argued that their plans for PSO's compliance were possible, they were not based on a comprehensive consideration of all of the factors which PSO considered;

7) other parties have not shown that doing nothing at the time the decisions were made was a reasonable, prudent plan - they had not shown that doing nothing would result in adequate electricity supplies in 2016;

8) since PSO's ECP was reasonable to meet its customers' 2016 electricity requirements and to be in compliance with EPA's 2016 emissions requirements, based on the information available at the time of PSO's decision to adopt the ECP, no part of the ECP should be subject to subsequent or hindsight review; and

9) since PSO's ECP was reasonable, its costs should be recovered in a timely manner, without imposing inordinate impacts on PSO's current or future customers.

Since PSO management's ECP decision, subsequent events have been favorable, and they are as follows:

1) It is Mr. Sartin's understanding that the Oklahoma SIP, adopted by the State of Oklahoma, and reviewed and approved by the EPA is now enforceable under Oklahoma and federal laws.

2) As described earlier, the OG&E litigation associated with the RHR has been completed, and there was no change ordered by the courts as to how EPA will implement the requirements of the RHR.

3) As a part of its plans to diversify its generation portfolio, PSO has added another net 450 mega-watts to its wind generation through purchased power agreements. This adds to PSO's fuel diversity, results in $53 million in annual cost savings,[8] and was discussed in prior testimony[9] as one means to address diversity.

4) The EPA continues to pursue rules which would increase the costs of existing coal generation.

5) PSO's costs of compliance have decreased as the environmental controls for Northeastern Unit 3 are much lower cost [*sic*] than the estimates provided in Cause No. PUD 201200054, and replacement power costs are lower.

6) Natural gas prices appear to have been moderated by the successful production of adequate supplies from new drilling technologies used by oil and gas companies.

7) The pace of change in the electric utility industry brought on by new technologies may be accelerating. Such changes may have a profound impact on historical views of fuel diversity predominantly focused on coal and natural gas. PSO's decision to avoid $650 million in coal environmental control investment to provide an expensive coal diversity option, appears even more reasonable.

8) The development of new technologies continues to progress, and in particular those related to distributed generation in the form of solar power. By not committing to the historical coal and natural gas diversity only strategy, PSO is well positioned to take advantage of new technologies as they develop over the next 10 years.

Mr. Sartin summarized his position regarding OCC approval as follows. PSO has explained at length the reasonableness of its ECP in this Cause and in prior Cause No. PUD 201200054. The OCC is requested to approve the cost recovery as requested by PSO, as the costs stem directly from the execution of the plan developed in response to the encouragement of Oklahoma's Attorney General, which included the submission of the Oklahoma SIP by the State

[8] PSO witness Fate testimony, page 23
[9] PSO witness Fate direct testimony, Cause No. PUD 201200054, page 22

of Oklahoma's Governor through the Oklahoma Secretary of Energy, adopted by the Oklahoma Department of Environmental Quality, which was reviewed and approved by the EPA.

In the next section of testimony, Mr. Sartin discussed PSO's capital structure, which is comprised of long-term debt and common stock equity. PSO is requesting a capital structure of 48% common stock equity and 52% long-term debt for the purpose of establishing new rates in this Cause.

The requested capital structure is consistent with PSO's recent historical structure, and is consistent with PSO's expected capital structure in 2016 upon completion of its large construction program, which is due in substantial part to the investment in environmental controls. This level is also consistent with the 48.7% common stock equity and 51.3% long-term debt in PSO's last base rate case, Cause No. PUD 201300217, which no party opposed.

PSO's test year end common stock equity of 44% and long-term debt of 56% is a temporary situation caused in large part by the recent issuance of $250 million of new debt, which temporarily skewed the structure to higher debt. This situation will be remedied during 2016 through the retention of additional retained earnings by PSO forgoing the payment of common stock dividends to AEP.

The proposed capital structure is important because it supports the overall credit ratings of PSO. Rating agencies use a number of factors in determining the credit rating of a utility. PSO is rated A3 by Moody's Investor Service.

The next topic covered by Mr. Sartin was the South West Power Pool, and its benefits to customers. As discussed in PSO witness Ross' Direct Testimony, SPP is a Federal Energy Regulatory Commission (FERC)-approved Regional Transmission Organization (RTO). PSO is a member of SPP. SPP, in its role as an RTO, provides transmission service to its members. The primary services SPP provides are reliability coordination, tariff administration, regional scheduling, transmission expansion, market operations, compliance and training, and generation dispatch. The services provided by SPP are required for PSO to provide electric service to its retail customers, and the cost of the service is governed by the OATT.

Mr. Sartin testified that AEP's transmission companies benefit PSO and retails [*sic*] customers. AEP Oklahoma Transmission Company, Inc. (OK Transco) is currently the primary AEP transmission company in SPP benefiting [*sic*] PSO and customers by reducing the financial burden on PSO of the substantial capital investment required by building new transmission facilities and rebuilding existing transmission facilities. Since 2010, as described in witness Sundararajan's testimony, OK Transco has invested $346 million in transmission facilities and plans to invest an additional $392 million over the next three years. These substantial investments would have increased PSO's financial burden, in particular during the time the environmental controls are under construction.

The transmission investments by OK Transco improves reliability for PSO's customers and for the SPP region by replacing aging infrastructure equipment and facilities, connecting new PSO customers to the transmission grid, adding capacity to PSO's electric system, and reducing transmission congestion, which can facilitate lower delivered cost of power to customers. OK Transco may also provide investments to interconnect new generation resources.

Transmission investments are also made to be in compliance with North American Electric Reliability Corporation and SPP reliability standards, as discussed in the Direct Testimonies of PSO witnesses Matthews and Robinson. The requirements of these standards are expected to increase over time, causing additional transmission investment and the resulting increased transmission costs.

SPP's Integrated Marketplace, in place since early 2014, may also increase transmission investment because the regional transmission grid will be operated in a different fashion. These market functions allow the electric system overall to be operated more efficiently, but this change in operation may identify additional transmission limitations that need to be remedied for the market to achieve even more efficient results.

Mr. Sartin further testified that the financial burden referred to above is explained as follows. Capital investment in any electric utility asset requires financing by electric utilities to the extent they cannot be funded with internally generated funds. This financing is provided by issuing debt to third parties and by common stock equity provided by AEP. During times of heavy capital investment, pressure is placed on the financial condition of utilities as cash is needed to construct new electric assets. During the time the assets are under construction, and prior to the time such assets are included in PSO's rate base and PSO is receiving cash revenues from customers, PSO's credit metrics deteriorate. Credit metrics are used by the bond rating agencies (e.g., Moody's Investors Service) to help determine bond ratings. Utility bond ratings are important because they determine the interest cost of the debt, and in some cases determine whether the utility has access to debt markets at all.

According to Mr. Sartin, PSO benefits from the reductions in cash construction expenditures which otherwise would weaken its financial condition. The financial burden of PSO's transmission capital expenditures is transferred to OK Transco, which is responsible for the debt and equity to support its assets. Improved PSO financial health benefits PSO and customers by helping ensure PSO can issue debt to support its capital spending needs for customers, and by helping to ensure a reasonable cost of debt through reasonable interest rates. Since the cost of debt is a part of the cost customers pay for electric service, reasonable debt costs directly benefit customers.

The reduced capital spending at PSO has been particularly beneficial the past few years because PSO is making substantial investments through mid-2016 in electric assets for environmental controls on its generating plants. This is in addition to the customary capital expenditures PSO continues to make for its generation, transmission, and distribution assets, all of which are required to provide reliable electric service to customers.

Mr. Sartin testified that over the period 2013 to 2015, PSO expected to spend an average of $316 million per year on new electric asset investments. This is a 70% increase over the prior three years (2010 to 2012) where PSO spent $186 million per year. So during the recent three-year period, OK Transco making capital investments, rather than PSO, was beneficial as it reduced the amount of long-term debt to be issued by PSO, reduced PSO common stock equity requirements, and improved PSO's credit metrics compared to what they would have otherwise been. Even with the benefits provided by OK Transco, it was Mr. Sartin's opinion that PSO still needed to increase its common stock equity as a percent of total capital structure.

The rating agencies review PSO's financial situation. Moody's Investors Service, a key rating agency, recognizes PSO's increased leverage (debt as a percent of total capitalization), and sizable environmental capital expenditure program that is expected to put downward pressure on financial metrics. Moody's has also noted the importance of timely cost recovery of the environmental expenditures to support the existing bond rating.

Moody's – February 5, 2015, Credit Opinion

SUMMARY RATING RATIONALE
PSO's rating reflects a vertically integrated electric utility company operating under a long-term credit supportive jurisdiction, economic vibrant service territory, and historically robust financial metrics. All of which are balanced against increased leverage and a sizable environmental capital expenditure program that is expected to exert downward pressure on financial metrics.

Rating Outlook
The stable rating outlook for PSO is based (on) the expectation that the company will maintain a constructive relationship with the OCC, successfully in [*sic*] attaining [*sic*] reasonable and timely cost recoveries while executing its capital investments and maintain key financial credit metrics that, despite some expected near-term weakness, will continue to support the rating.

Howard L. Ground

Mr. Howard L. Ground, an independent contractor providing regulatory and environmental services, testified on behalf of Public Service Company of Oklahoma (PSO).

Mr. Ground's current testimony reviewed his previous testimony filed in Cause No. PUD 201200054. The previous testimony was filed on behalf of PSO in order to authorize cost recovery associated with PSO's environmental compliance strategy to address certain air emission rules being considered by the Environmental Protection Agency (EPA) at the time. His current testimony provides an update to the prior testimony to include subsequent developments.

Mr. Ground's previous testimony in Cause No. PUD 201200054 described two EPA rules, the Regional Haze Rule (RHR) and the Mercury and Air Toxics Standard (MATS), and described the executed term sheet for a Settlement Agreement with the EPA, the State of Oklahoma, and the Oklahoma Department of Environmental Quality (ODEQ) that was later finalized and fully implemented. The Settlement Agreement resolved PSO's challenge to the EPA's RHR Federal Implementation Plan (FIP) for Northeastern Station Units 3 and 4, and allowed PSO to cost-effectively meet compliance obligations under RHR and MATS and insure sufficient resources to meet customer's electricity needs.

Mr. Ground described why his testimony in Cause No. 201200054 is relevant to this Cause and updated the Commission on relevant subsequent developments. He stated that the case describes PSO's contemporaneous evaluation of the information available at that time and then updated the Commission on the final federal approval of the revised Oklahoma RHR State Implementation Plan (SIP), which makes the terms of the Settlement Agreement final and enforceable as a matter of state and federal law. Next, he provided information concerning the resolution of litigation related to Oklahoma's RHR SIP in the federal courts of appeals; the ongoing litigation over MATS at the U.S. Supreme Court; and the extension approved by ODEQ to allow PSO to meet its obligations under MATS. Finally, he described recent developments that could lead to additional cost increases to maintain and operate coal-fired generating units in the future, including Clean Air Interstate Rule (CAIR), future RHR planning requirements, the effect of the current Coal Combustion Residuals (CCR) regulation requirements, the final Clean Water Act 316(b), 316(b) rule implementation, greenhouse gas emission rules, and an update on the National Ambient Air Quality Standards (NAAQS).

Mr. Ground described the coal combustion residual rule as being the preferred non-hazardous option and the final 316(b) rule as being managed through the National Pollution Discharge Elimination System (NPDES) permit renewal process. In regards to subsequent developments related to Greenhouse Gas (GHG) Emissions, he stated that the EPA proposed new guidelines called the "Clean Power Plan" (CPP) to reduce GHG emissions from existing power plants in June 2014. Mr. Ground testified that until final guidelines are issued and state plans are approved, or a final federal plan is promulgated, the ultimate costs associated with the CPP are unknown. However, American Electric Power (AEP) filed extensive comments on the CPP, challenging the legal and technical bases for EPA's proposal.

Mr. Ground described that in addition to the ongoing implementation of the new one hour NAAQS for Sulfur Dioxide (SO_2) and Nitrogen Dioxide (NO_2), the EPA has also finalized new, lower ambient air quality standard for Particulate Matter (PM) in 2013, and proposed a new, lower range for the ozone NAAQS in 2014. Since both SO_2 and NO_2 are precursors for PM 2.5, and NO_x is an ozone precursor, the controls being installed at Northeastern 3 and the retirement of Northeastern 4 will assist Oklahoma in achieving or maintaining the SO_2, NO_2, PM and ozone NAAQS.

Overall, Mr. Ground testified that subsequent developments since his previous testimony support PSO's continued commitment to the initial decision. PSO faced a compliance deadline with a FIP and a new emission control requirement from EPA that placed specific requirements for new controls on its 35-year old coal-fired units that would have far exceeded their initial construction cost without any assurance of how many years the units would continue to operate. There were also a number of other EPA emission control requirements being proposed that provided great uncertainty as to the ability to meet customer demands and maintain system reliability.

According to Mr. Ground, the settlement agreement allows PSO to operate half of its coal-fired units to a very respectable 50-year life at a very reasonable cost. He further stated that the settlement agreement minimizes the impact of any future EPA regulation and gives customers certainty that PSO will be able to continue to provide safe and reliable energy in a cost effective manner.

Steven L. Fate

Mr. Steven L. Fate, Director Business Operations Support for the Public Service Company of Oklahoma ("PSO" or the "Company"), an operating company subsidiary of American Electric Power Company, Inc., testified on behalf of the Company.

Mr. Fate's testimony supported the Company's request for approval to recover certain costs associated with its plan to be in compliance with the federal Clean Air Act's Regional Haze Rule ("RHR") and the Mercury and Air Toxics Standard ("MATS"). According to Mr. Fate, the compliance plan which affects Northeastern Units 2, 3, and 4; Oklaunion; Southwestern Unit 3; and Comanche; consists of a variety of compliance measures including: (1) new post-combustion emission control equipment and associated reagents, (2) modifying existing generating equipment, (3) fuel changes, (4) unit operating limits, (5) unit retirements, and (6) contract replacement power.

Mr. Fate described why PSO needed a comprehensive environmental compliance plan, how the plan was selected, and the various beneficial characteristics of the plan as compared to other alternatives. He testified that PSO needed a compliance plan because all of the compliance options were projected to have a significant impact on PSO's electrical generation and cost. The plan allowed PSO to effectively implement the complex multi-year effort while controlling costs and insuring adequate resources were available to meet customer demand.

In evaluating the various compliance options, PSO considered a variety of overarching factors. Since the economic evaluation of compliance alternatives did not indicate there was one clearly lower cost alternative, these other important considerations help the Company make a fully informed decision. PSO consider [*sic*] additional factors such as the uncertainty around additional environmental regulations and the impact to various stakeholders including the City of Oologah, Rogers County, the City of Tulsa, employees, and shareholders. All these factors considered, PSO chose a plan that afforded the opportunity to make generating resource acquisition decisions on an incremental basis while keeping as many options open as possible over a longer period of time.

Mr. Fate further testified that PSO continues to believe that fuel diversity is of value in mitigating price volatility, but that locking in a particular fuel source for an extended period in [*sic*] face of substantial uncertainty and at a substantial upfront cost of $650 million was not the best option. PSO's compliance plan continues to provide the benefit of solid-fuel generation well into the future at a lower initial investment cost. In addition to the highly-efficient natural gas generation already secured through a competitive bidding process, the additional time will allow PSO to replace the retiring generation with additional energy efficiency, [*sic*] demand response, and cost effective renewable resources. PSO has already begun taking steps to diversify generation by securing an additional 600 mega-watts of low cost wind generation that is expected to save customers $53 million in 2016 and over $720 million over the life of the contracts.

According to Mr. Fate, as part of the compliance plan, the Company decided to conduct a Request for Proposals ("RFP") for Purchased Power Agreements ("PPA's") to fill the projected 252 mega-watt capacity reserve deficiency resulting from the retirement of Northeastern Unit 4 in 2016. PSO chose PPA's as the replacement option because there was insufficient time to permit and construct a new natural gas-fired combined-cycle unit and the Company believed there were more economical options available in the market. The RFP process, overseen by the Boston Pacific Company acting as an Independent Evaluator, resulted in the selection of a fifteen (15) year PPA for 260 mega-watts of capacity from the Oneta generating facility located near Tulsa.

In June 2013, PSO submitted an update to its 2012 Integrated Resource Plan due to material changes in assumptions, the most significant of these being an increased load forecast. In response to the forecasted need, PSO secured additional generation resources through an RFP process that at the time was underway for the benefit of PSO's sister operating company, Southwestern Electric Power Company ("SWEPCO"). Through SWEPCO's RFP, conducted consistent with the Louisiana Public Service Commission's competitive bidding rule, PSO securing [*sic*] two additional low cost contractual capacity and energy resources from the Green Country Facility in Jenks, Oklahoma for 124 mega-watts for five years and a three year, 40 mega-watt contract with Tenaska, sourced from the Eastman Cogeneration Facility in Longview, Texas.

Mr. Fate testified why it is reasonable to recover the cost of reagents used in environmental control systems in the Fuel Cost Adjustment rider ("FCA") and supported the Company's request to recover reagent costs recorded in FERC accounts 502 and 549 through the FCA. Reagents are used in the generation of electrical energy and their consumption rates are variable and highly correlated to the amount of fuel consumed and electrical generation produced. Mr. Fate provided an estimate of $4.76 million for the cost of reagent between March 2016 and February 2017, the first twelve month [*sic*] of full operation of environmental controls on both Northeastern Unit 3 and Oklaunion.

Kevin J. Munson

Mr. Kevin J. Munson, who is employed by American Electric Power Service Corporation (AEPSC), as Project Director – Western Fleet Environmental Program, testified on behalf of PSO. Mr. Munson testified that he is responsible for the project management of the flue gas desulphurization (FGD) and nitrogen oxide (NOx) reduction projects for PSO and AEP's western affiliates.

Mr. Munson stated that he testified in Cause No. PUD 201200054 and provided an overview of the Northeastern Power Station and explained the estimated project cost for installing the environmental controls on Northeastern Unit 3 in support of PSO's environmental compliance strategy to comply with the Regional Haze Rule (RHR) and the Mercury and Air Toxics Standards (MATS). Mr. Munson stated that he also described in Cause No. 201200054, PSO's technical and direct capital cost comparison of viable emission reduction technologies that resulted in the election to retrofit Northeastern Unit 3 with dry sorbent injection (DSI), activated carbon injection (ACI), and a fabric filter (FF) baghouse. Mr. Munson attached his testimony in Cause No. PUD 201200208 [*sic*] as Appendix A to his testimony in this proceeding. Mr. Munson stated that his testimony in Cause No. PUD 201500208 updates and details the progress and costs to date of the project described in Cause No. 201200054.

Mr. Munson provided a list of the primary equipment that will be installed as part of the environmental controls at Northeastern Unit 3 as follows:

- Pulse-Jet FF with byproduct material handling
- DSI Sorbent Reagent Silo with blowers and injection piping system
- Activated Carbon Storage Silo with blowers and injection piping system

- Booster Fan to account for additional resistance from the FF

Mr. Munson explained that the environmental controls project at Northeastern Unit 3 is currently in Phase III, which began in the first quarter of 2014. Phase III is the last in the three-phased approach to the project and involves full-scale construction, startup, and commissioning activities.

Mr. Munson stated that the current projected in-service date for the environmental controls is February 15, 2016.

Mr. Munson described that the current estimated direct capital cost of Northeastern environmental controls project is approximately $164.5 million excluding AFUDC and Company allocated overheads. The current project estimate is a decrease from the $175 million estimate provided in testimony in Cause No. PUD 201200054. Mr. Munson stated that the cost estimate includes the installation of the DSI, ACI, and FF systems, and other associated upgrades to existing station equipment, including unit control interconnections, an induced draft booster fan (ID fan or booster fan), equipment relocations, and other material handling equipment costs, as well as, costs for support of the project from AEPSC.

Mr. Munson testified that a timely compliance strategy decision by PSO provided a clear path for the project team to efficiently and effectively manage and control project costs.

Mr. Munson stated that the project total cost will be monitored and managed by assembling costing information from the procurement and accounting process to provide Estimate at Completion (EAC) projections on a monthly basis. The EAC projection as of April 2015 is approximately $162.5 million and represents a slight decrease from the current Phase III improvement requisition amount of $164.5 million.

Mr. Munson further explained that the final cost for the environmental controls is projected to be $190.6 million based on the $162.5 million project direct-cost EAC projection noted above and assumptions made for the interest in AFUDC calculation and Company overhead allocations.

Finally, Mr. Munson described other environmental compliance projects to meet the requirements of the Oklahoma Regional Haze Rule State Implementation Plan. Mr. Munson testified that PSO has installed low NOx burners (LNB) and overfire air (OFA) at Northeastern Unit 2 and Southwestern Unit 3. Mr. Munson stated that the LNB/OFA projects at both Southwestern Unit 3 and at Northeastern Unit 2 were completed and placed in service on June 25, 2013, and January 24, 2014, respectively. Mr. Munson further stated that low NOx combustor modifications were being conducted at Comanche Units 1G1 and 1G2.

<u>Mark A. Becker</u>

Mark A. Becker, employed by the American Electric Power Service Corporation (AEPSC) as a Resource Planning Manager, testified on behalf of Public Service Company of Oklahoma (PSO or Company).

Mr. Becker received a Bachelor of Science degree in Electrical Engineering from the University of Arkansas in 1983 and has over 30 years of experience working for investor-owned and municipal electric utilities and energy trading companies. The majority of Mr. Becker's experience, approximately 25 years, has been related to performing a utility's resource planning and operational analysis functions using the proprietary long-term resource optimization software models known as Strategist®, and more recently PLEXOS®.

The purpose of Mr. Becker's testimony was to adopt and resubmit in its entirety the original Direct Testimony of Scott C. Weaver from Cause No. PUD 201200054, which supported the long-term economic analysis PSO relied upon to determine its Environmental Compliance Plan ("ECP"). Mr. Becker's testimony also provided updated evaluations which supported PSO's determination that implementation of the ECP was reasonable, even after considering events that occurred since that original filing. The most notable event was the EPA's June 2014 proposed rule on carbon dioxide (CO_2) emissions based on Section 111(d) of the Clean Air Act, also known as the Clean Power Plan (CPP).

As an exhibit, Mr. Becker provided the original Direct Testimony of Scott C. Weaver from Cause No. PUD 201200054 that he adopted during the rebuttal phase of that cause. That testimony was based on an analysis that was performed predominantly in late 2011 and was used to evaluate the Company's then ongoing settlement discussions with the EPA, Oklahoma Department of Environmental Quality (ODEQ), and others. That analysis showed there were relatively small differences in the estimated long-term study period costs of each of the alternatives PSO could use to meet its environmental requirements. The compliance options evaluated for PSO's two coal-fired generating units at its Northeastern Power station were: (1) retrofit both units with certain environmental controls, (2) replace both units with new natural gas plants or power purchases, or (3) a combination of environmental controls at one unit and retirement and replacement of the second unit. According to Mr. Becker, as a result of the economic analysis and other factors outlined in PSO witness Fate's Direct Testimony, PSO chose the third alternative as the preferred method for meeting its emission compliance requirements.

A follow-up analysis was performed in August 2012 due to increases in environmental retrofit capital cost. While continuing to reflect relatively small economic differences among the available alternatives, the analysis indicated that PSO's chosen path compared as well, or even more favorably, to the other options.

In 2013, the reasonableness of the ECP was once again reaffirmed in light of changed assumptions for load growth and supply resources.

Then, in June 2014, the EPA announced its proposed CPP that would seek to reduce the intensity of individual states' CO_2 emissions from existing fossil fuel generation resources. In response, the Company performed an analysis of the relative economics of the ECP versus other potential replacement options. Although the CPP rule is not in its final form, and the actual costs of compliance are not currently knowable, the updated analysis evaluated the impacts of a scenario with even higher costs of CO_2 emissions, and a zero emission cost scenario. The results of this economic analysis once again reaffirmed PSO's compliance plan.

Mr. Becker's testimony concluded that PSO's ECP continues to be reasonable since none of the critical assumptions, and economic evaluation results, have changed significantly since the original analysis in 2011.

Richard G. Smead

Richard G. Smead of the firm RBN Energy LLC testified on behalf of PSO. Mr. Smead addressed the ability of the natural gas market to supply ample natural gas at reasonable prices for the foreseeable future, specifically to PSO and to PSO's power supplier under a proposed purchased-power agreement. According to Mr. Smead, his testimony was provided in order to validate PSO's supply assessment in deciding to phase out the Northeastern 3 and 4 coal-fired units and replace certain of the generation with gas-fired power in terms of the overall state and future of the U.S. and Oklahoma natural gas market. Mr. Smead presented and confirmed his Responsive Testimony for another party in the so-called "54 Case," originally addressing such matters, in which he also supported PSO's decision. Mr. Smead updated his 54 Case testimony and exhibits to account for the passage of time since it was filed, and to confirm its continuing validity. Mr. Smead provided a much broader overview of the current state of the U.S. natural gas industry than was included in his earlier testimony, including forecasts by the U.S. Energy Information Administration (EIA) and by his own firm. To fully update the record on these issues, Mr. Smead addressed countervailing factors such as rig-count reductions caused by low oil and gas prices and public concerns about hydraulic fracturing. According to Mr. Smead, those factors did not undermine supply forecasts.

Mr. Smead concluded that, as is explained in detail in his prior 54 Case testimony included as Exhibit RGS-2, and as updated, confirmed and expanded here, PSO has made an extremely well-founded commitment to natural gas as a major part of its environmental solution. Mr. Smead testified that the supply is there, prices can be expected to be low and stable, and this situation should stay in place for many decades. To reach that conclusion, Mr. Smead notes that EIA's more recent forecast scenarios of natural gas prices have fallen well below the forecasts made by the same agency at the time of his 54 Case testimony, and that in all cases, the most likely natural gas price scenarios are below the price levels assumed by PSO in making its fuel choice. Similarly, the expected price of the coal to be replaced by natural gas is higher at the time of the replacement than the prices assumed by PSO. Mr. Smead concluded that the economics of the replacement can be expected to be significantly more favorable than assumed by PSO.

Mr. Smead then tests the reasonableness of EIA's current forecast of natural gas prices by observing the progression of those forecasts during the five or six years since EIA has increasingly taken into account the abundance of natural gas occasioned by the shale revolution. He showed that the projections of price have steadily declined by approximately $5.00 per MMBtu.

In examining the specific situation in Oklahoma, Mr. Smead showed that in-state production has been steadily increasing its surplus over in-state consumption, adding 56 percent to the exportable surplus since 2007, when the shale revolution became apparent in Oklahoma. Continuing the Oklahoma-specific analysis, Mr. Smead demonstrated the large and flexible pipeline connectivity both within the state and with other massive supplies from other parts of the country, with Oklahoma essentially being at the confluence of major pipeline industry expansion from rapidly growing supply regions, at the same time that it is a major producer/exporter of natural gas itself. The conclusion Mr. Smead reached here was that access to natural gas supplies is virtually unlimited for consumers in Oklahoma.

Last, Mr. Smead addressed two factors that some argue would threaten continuation of this abundance, declining drilling rig activity and opposition to development using hydraulic fracturing. According to Mr. Smead, technology and productivity have more than overcome drilling-rig decline in response to low oil and gas prices - an 86-percent decline in gas-directed drilling rig count since 2007 has been accompanied by a 46-percent increase in national production of natural gas, thanks to large increases in the amount of new natural gas added by each rig. Further, according to Mr. Smead, despite opposition to hydraulic fracturing by certain parties, their reactions to the examination of the subject by the U.S. Environmental Protection Agency (EPA) indicate that the worst-case outcome for the natural gas industry would possibly be some additional costs that would be unlikely to increase prices, rather than any significant constraint in supply.

Combining all of these threads, Mr. Smead concluded that PSO has made an extremely well-founded commitment to natural gas as a major part of its environmental solution. Mr. Smead testified that the supply is there, prices can be expected to be low and stable, and that situation should stay in place for many decades.

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 of Public Service Company of Oklahoma (PSO).

Mr. Hamlett's testimony presented PSO's overall rate base and cost of service, including certain known and measurable ratemaking adjustments to the test year amounts and the resulting revenue deficiency. PSO's filing is based on the financial results for the test year ending January 31, 2015. He presented and supported various application package schedules along with certain supplemental package schedules. His EXHIBIT RWH-2 provided a listing of the adjustments and the company witness that sponsors each adjustment.

Mr. Hamlett requested that the OCC approve PSO's request to defer and recover storm maintenance expenses in the same manner as approved in Cause No. PUD 200800144 which was not altered in Cause Nos. PUD 201000050 and 201300217. He also included amortization of storm recovery expense as approved in Cause No. PUD 201300217.

Mr. Hamlett requests that the Commission continue its current practice regarding recovery of rate case expenses.

Mr. Hamlett describes how SPP open access transmission tariff expenses are recovered and notes PSO does not propose any change in how these costs are being recovered. Mr. Hamlett then describes the proposed over/under deferral accounting for costs being recovered through the SPPTC tariff.

In addition, Mr. Hamlett supports the incremental annual revenue requirements associated with PSO's Oklahoma Environmental Compliance Plan and Environmental Compliance Rider. The proposed rider will be applicable to assets that will be placed into service in 2016. Mr. Hamlett testifies that the overall revenue requirement related to the environmental compliance plan is $101 million. This reflects an update or increase of $2 million to Mr. Hamlett's original filed testimony to account for $13.4 million of low NOx burners placed into service in 2012 for Northeastern 3 & 4 that was not included in his original EXHIBIT RWH-4. This update does not change PSO's total cost of service. Mr. Hamlett's EXHIBIT RWH-4 provides amounts for items that are: 1) in current base rates; 2) proposed to be in the environmental compliance rider or base rates; 3) in proposed base rates; and 4) in the fuel factor.

According to Mr. Hamlett, the application package (AP) Schedule B-01 showed a revenue deficiency of $83,828,642 on a total company pro-forma basis. The following table summarizes the results presented in PSO's AP.

Description	Schedule Reference	Total Company Pro-forma
Rate Base	B-02	$2,067,248,140
Rate of Return	F-01	7.60%
Operating Income Requirement		$157,110,859
Pro-Forma Operating Income	B-02	$105,926,719
Operating Income Deficiency		$51,184,130
Revenue Conversion Factor		1.639100
Revenue Deficiency		$83,828,642

Mr. Hamlett testified the Company's Oklahoma jurisdictional pro-forma rate base at July 31, 2013, was $2,062,158,913 (AP Schedule B-02, Lie [*sic*] 21, col. 7). The Oklahoma jurisdictional pro-forma operating income was $105,214,378 (AP Schedule B-02, line 22, col. 7). The resulting Oklahoma jurisdictional return earned on rate base for the adjusted test year ending July 31, 2013, was 5.10% (AP Schedule B-02, line 23, col. 7).

John J. Spanos

John J. Spanos with the firm of Gannett Fleming Valuation and Rate Consultants, LLC, testified on behalf of Public Service Company of Oklahoma (PSO or Company).

Mr. Spanos sponsored the depreciation study performed for PSO. The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2014. The proposed rates appropriately reflect the rates at which PSO's assets should be depreciated over their useful lives and are based on the most commonly used methods and procedures for determining depreciation rates.

According to Mr. Spanos, the table 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, 2014.

	Current		Proposed	
Function	Rates	Proforma Expense	Rates	Expense
Steam	1.58	19,717,787	3.40	42,410,973
Other	2.04	3,155,160	3.28	5,072,213
Transmission	1.94	15,243,751	2.73	21,450,520
Distribution	2.40	50,040,428	3.17	66,098,128
General	3.24	5,076,641	2.80	4,392,348
Unrecovered Reserve Amortization	-	0	-	471,408
Total		93,233,767		139,895,590

The major components that caused rates to change by function are as follows:

- Steam Production Plant: the utilization of interim survivor curves as compared to interim rates of retirement and an increase in negative net salvage.
- Other Production Plant: the utilization of interim survivor curves as compared to interim rates of retirement and an increase in negative net salvage.
- Transmission Plant: the more negative net salvage percents for some accounts.
- Distribution Plant: the more negative net salvage percents for many accounts.
- General Plant: the application of amortization rates to the more appropriate vintages for some accounts.

Mr. Spanos further testified that the rates currently in affect [*sic*] were inadequate due to the results of the last proceeding. In the last proceeding, the statistical net salvage analyses resulted in much more negative percentages than the agreed-upon percentages. Thus, the costs incurred were higher than theoretically recovered in the depreciation accruals for net salvage. This created a larger variance of the theoretical reserve to actual book reserve to be recovered based on the proposed depreciation rates. These inadequate accrual rates have been in place since January 2009.

In his testimony, Mr. Spanos also addresses the need to include a dismantlement component for generating facilities.

Mr. Spanos testified he performed his depreciation study by using the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation was based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 391, 391.11, 392, 393, 394, 395, 396, 397, 398 and 399.3, he used the straight line remaining life method of amortization. The account numbers identified throughout his testimony represent those in effect as of December 31, 2014. The annual amortization was based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

To determine the recommended annual depreciation accrual rates, he did this in two phases. In the first phase, he estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Mr. Spanos further testified that he made a field review of PSO's property during August 2013 to observe representative portions of plant. According to Mr. Spanos, field reviews are conducted to become familiar with Company operations and to obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Mr. Spanos testified that the depreciation study reflected the recovery of Northeast Units 3 and 4 utilizing the retirement date of 2026. According to Mr. Spanos, based on the most recent Company plans, it is now probable that Northeast Unit 4 will be retired in 2016 and Northeast Unit 3 will be retired in 2026. These short remaining lives would cause a large increase in annual depreciation expense. Therefore, the rates in the Depreciation Study reflect recovery of plant in service until April 2016 when Unit 4 is retired and then revised rates after April 2016 for the remaining plant in service for Northeast Unit 3.

Thomas J. Meehan

Thomas J. Meehan, Senior Vice President, and Project Director with Sargent & Lundy, LLC (S&L), testified on behalf of Public Service Company of Oklahoma (PSO). Mr. Meehan's 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. The studies are included in EXHIBIT TJM-3 and detail the estimates to dismantle the following PSO generating facilities:

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

According to Mr. Meehan, S&L had prepared over 288 demolition cost estimate studies on 83 power plants in recent years and that [*sic*] demolition cost estimates have been common throughout the firm's 124 year history serving the electric power industry. The firm's work includes early power plant site development, power plant permitting, conceptual power plant engineering and design, detailed power plant engineering and design, and construction management and commissioning of power plants. Activities include both new power plant work as well [*sic*] the maintenance or upgrading of power plant configurations for a variety of plant changes. Mr. Meehan testified that S&L is on major industry code committees and assists in developing and establishing technical engineering code requirements to ensure public safety.

Mr. Meehan further testified that S&L was one of the most experienced power plant architectural engineering firms in the world; and has worked on nuclear power plants, fossil fueled power plants (e.g., coal fired, oil fired, natural gas fired, etc.), and renewable energy facilities. Every new generation power plant design project and every power plant retrofit project that has been performed by S&L throughout its 124-year history has involved some type of site grading and/or demolition. This fact is true whether the assignment was related to the full decommissioning and demolition of a facility or a partial demolition to accommodate the development of new facilities and/or the retrofit of existing facilities. A summary list of recent demolition estimates prepared by S&L is provided in EXHIBIT TJM-2.

Mr. Meehan testified there are a number of reasons why it was necessary to dismantle a generating station at the end of its useful life. In order to reuse land, structures and facilities would need to be removed. Since the number of generating station sites in the nation is limited, it is likely that after the retirement of the units, future generating stations would be located at these sites to take advantage of exiting 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, stacks for example, could collapse causing damage and public safety risks. In some cases, removal and disposal of asbestos or other potentially hazardous materials may also be required.

Mr. Meehan described how S&L performed its studies of the cost of dismantling PSO's electric generating facilities. S&L provided an update to existing PSO electric generating facility demolition cost estimates that were prepared in 2013 by S&L. The purpose of the update was to capture any changes that may have occurred at the PSO facilities between 2013 to 2015 that would affect the demolition costs. As with past studies, the method of updating these cost estimate studies started with participating in kickoff meetings in March 2015 and April 2015 at each plant with representatives of PSO to determine the scope of work and assumptions and also gather updated information to be used in the studies. The unique characteristics of each site were captured by reviewing general arrangement drawings and aerial photographs of each site and walking down the facility with plant representatives. These documents showed the location of major facilities on site and the arrangement inside the power blocks, such as the boiler building, the turbine building, etc.

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, S&L assumed that there was sufficient room on site to dispose of all the non-hazardous debris. S&L assumed 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 demolished in an inefficient manner). Assumptions such as these 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 2013 study.

Mr. Meehan testified that the updated 2015 demolition cost estimates capture current labor, material, and scrap pricing adjustments. Changes in labor rates and market value of scrap 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 2013 demolition cost estimates were prepared. For example, at the Oklaunion Plant, the 2015 cost estimate accounts for a new 650 acre-feet evaporation pond that will be constructed in the near future. The Southwestern Plant 2015 cost estimate accounts for the removal of fuel oil storage tanks (included in the 2013 estimate) that were recently demolished. The demolition cost estimate reports identify all of the revisions that were included.

Mr. Meehan testified that the cost estimates used demolition techniques and labor crew mixes that are comparable to those used by major demolition contractors who have successfully bid and executed demolition work. Given this, it is not necessary for S&L to have actually bid and executed the work in order to produce demolition cost estimates.

<u>Robert B. Hevert</u>

Company Witness Robert B. Hevert's Direct Testimony presents evidence and provides a determination as to PSO's current required Return on Equity (ROE), and assesses the reasonableness of the Company's capital structure and cost of debt.

An ROE that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial integrity. Mr. Hevert testified that because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. By their very nature, those models produce a range of results from which the ROE is estimated. That estimate must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. Consequently, the key consideration in determining the ROE is to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general, and the subject company (in the context of the proxy companies) in particular.

Mr. Hevert relied on four widely-accepted approaches to develop his ROE determination: (1) the Constant Growth Discounted Cash Flow (DCF) model; (2) the Multi-Stage DCF model; (3) the Capital Asset Pricing Model (CAPM); and (4) the Bond Yield Plus Risk Premium approach. However, over the course of the study period, the proxy companies have traded at P/E ratios well in excess of their historical average, and in excess of the market. Because that condition is unlikely to persist, it violates a principal assumption of the Constant Growth DCF model, i.e., that the P/E ratio will not change, ever. As a practical matter, the Constant Growth DCF results are well below a highly observable and relevant benchmark: the returns authorized for vertically integrated electric utilities. A more balanced approach therefore is to consider multiple methods, including both forms of the DCF model, the CAPM approach, and the Bond Yield Plus Risk Premium model. Reviewing those results, Mr. Hevert recommended that an ROE in the range of 10.25 percent to 10.75 percent represented the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets.

Within that range, Mr. Hevert concluded that ROE of 10.50 percent reasonably represents the return required to invest in a company with a risk profile comparable to PSO. Mr. Hevert's recommendation considered the proxy group analytical results as well as additional factors including: (1) the composition of PSO's generation portfolio and the risks associated with environmental regulations; (2) PSO's high level of planned capital expenditures; (3) flotation costs; and (4) the effect of certain rate mechanisms on the Company's relative risk profile.

As to the Company's requested capital structure, which includes 48.00 percent common equity and 52.00 percent long-term debt, Mr. Hevert notes that the proposed equity ratio is at the low end of the range of ratios in place at comparable operating utility companies and therefore represented a relatively high level of financial risk.

Lastly, Mr. Hevert finds the Company's proposed 4.92 percent cost of debt is reasonable based on a review of the prevailing yield on Bloomberg Fair Value Curves for A-rated and BBB-rated utility debt concurrent with the date of issuance of the Company's debt instruments.

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 Public Service Company of Oklahoma (PSO).

Mr. Frantz is responsible for maintain the accounting books and records, and regulatory reporting for AEPSC. He is also responsible for AEPSC's monthly service billings to its affiliates. His responsibilities for AEPSC also include compliance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts accounting and reporting requirements.

Mr. Frantz' testimony provided an overview of the affiliate costs included in PSO's test year results; an explanation of how AEPSC is organized to provide services to PSO and other affiliates; an overview of the management oversight and quality assurance controls in place to ensure that affiliate billings properly reflect the cost of providing the service to each affiliate; a discussion of the external oversight of AEPSC accounting and billing processes; a discussion of AEPSC's use of benchmarking and market comparison data to ensure services provided to PSO and other affiliate companies are done so effectively and efficiently; a discussion of the AEPSC billing process for the services provided by AEPSC to PSO and the other affiliates; and an overview of the types of affiliate services provided to PSO by affiliates other than AEPSC.

Mr. Frantz testified that the PSO cost of service amount presented in this filing includes $62,630,550 of affiliate costs. (W/P P-7). AEPSC accounts for $60,658,835 of these costs, which are summarized on EXHIBIT BJF-1, with a more detailed view on EXHIBIT BJF-2. PSO has included $1,971,724 billed from other affiliates in cost of service. These other affiliate costs are detailed on W/P P-7.

According to Mr. Frantz, PSO's total company operations and maintenance (O&M) expense as shown on Schedule H of the filing package is $284.0 million, and the $62.6 million of affiliate costs included in that amount represents 22 percent of the total O&M being requested in this case. The remaining 78 percent is incurred directly by PSO and not through an affiliate.

Mr. Frantz' testimony described the organization and functions of AEPSC and described in detail the broad array of services it provides to PSO. He discussed the management oversight of the billings from AEPSC to affiliates as well as the variety of external oversight and review of AEPSC billing processes. He provided a discussion of how benchmarking and market comparison studies are used by AEPSC to ensure that the services provided are done in an efficient and effective manner. He also provided information regarding the accounting practices followed by AEPSC to assign and allocate costs properly to PSO and other affiliates.

Mr. Frantz testified that 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. The performance of many of these functions by AEPSC increases efficiency by eliminating the need for each operating company to maintain staff and resources to perform the services separately. Thus, the relationship that PSO enjoys with AEPSC is of substantial benefit to PSO and its customers.

Andrew R. Carlin

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

The purpose of Mr. Carlin's testimony was to demonstrate that the compensation paid to PSO employees, PSO's allocated share of compensation paid to AEPSC employees, and the amount PSO seeks to include in its cost of service is reasonable and a necessary cost of doing business. Witness Carlin also makes evident that the company's total payroll costs are market-competitive, vital for the attraction and retention of employees with the skills and experience necessary to efficiently and effectively operate PSO's business, and beneficial to customers.

According to Mr. Carlin, the Company's compensation strategy for all position levels is to provide employees with a market competitive total cash compensation (TCC) opportunity which is a base salary (or base rate) along with a variable performance-based portion that is identified as incentive compensation. Management positions can also have variable long-term incentive compensation opportunity. When long-term incentive compensation opportunity is added to TCC, it is labeled total direct compensation (TDC). TCC and TDC opportunity are the same for non-management employees, and are referred to collectively as "total compensation," when assessing market pay competitiveness. The Company designs its compensation programs to provide total employee compensation that, on average, is at the median of comparable pay offered for similar positions by companies from which the Company needs to attract and retain its employees.

Mr. Carlin further testified that the Company primarily uses compensation surveys to compare its compensation rates and practices to those of other similar companies. Changes to the Company's compensation rates and practices are generally made annually to maintain competitive compensation for each position relative to these survey comparisons of market competitive compensation. The Company's compensation department participates in or purchases numerous third-party compensation surveys each year that aid in ensuring that the Company's compensation levels are reasonable and market competitive. These surveys provide extensive compensation information for statistically significant samples of incumbents in a wide variety of jobs.

Specifically, the compensation department matches Company positions to the jobs included in these surveys and compares the compensation levels and practices for these positions with those of similar companies for similar positions with similar responsibilities, size and scope. After accounting for any differences in position scope, the compensation department uses market median total compensation, which includes the target value of all variable incentive compensation, as the primary compensation benchmark for each position. Salary is also used as a point of comparison for all positions and TCC is also included as a point of comparison for positions for which the Company provides a long-term incentive compensation opportunity. This process for assigning and reviewing salary ranges and incentive targets is consistent with the compensation practices of the majority of electric utilities and other large U.S. companies.

Mr. Carlin testified that total compensation is chosen as the primary point of comparison because it includes all statistically significant types of compensation. The survey data demonstrates that annual incentive compensation is a significant and often substantial component of market competitive compensation for nearly every position. The survey information also shows that long-term incentive compensation is a significant and often substantial component of market competitive compensation for high level exempt, professional, managerial and executive positions. Therefore, no assessment of market competitive compensation would be complete or valid without including the annual incentive compensation portion of all positions and including long-term incentive compensation for high level exempt professional, managerial and executive positions. The value of any incentive compensation offered by both the market and the Company is researched and considered in assigning a job grade to each position. Because of this practice, the Company's base pay levels are typically lower than those of companies that provide less or no incentive compensation opportunity.

Mr. Carlin did not believe it would be reasonable to reduce or eliminate a portion of employee incentive compensation without providing an offsetting pay increase to maintain a market competitive employee compensation package.

According to Mr. Carlin, base salaries for salaried positions are set by Company management within the salary range for the job grade assigned to each position based on the qualifications and experience of the employee relative to the requirements for the position. For jobs with multiple incumbents, the base salaries of other employees in the same position are also a major factor.

The Company also maintains a merit increase program for all salaried positions. The amount budgeted annually for merit increases is established by senior AEP management based on salary planning surveys, the market competitiveness of the Company's compensation and the budget dollars available for salary increases. The merit program generally provides an annual salary increase opportunity to salaried employees based on their individual performance. For 2013 and 2014, the Company's merit budgets were 3.0 percent, which was at or very near the market median for all employee categories. However, the Company's merit budgets averaged less than the market competitive level for several previous years and the Company's pay levels did not keep pace with market competitive compensation during this period and has not subsequently caught up. The overall 2015 base pay increase budget was 3.5% for both salaried and hourly craft employees. For salaried employees this was comprised of a 3.0 percent merit budget and a 0.5% promotion and other adjustment budget. For hourly craft employees this was comprised of a 3.0 general increase budget and 0.5% budgets for both market equity and geographic wage equalization.

As part of the merit program, each employee's individual performance is evaluated on at least an annual basis. The amount of the "merit" increase awarded to each employee, if any, is based on a combination of factors, including their individual performance rating, their performance relative to their peers, the position of their salary within the salary range for their job, and the size of the merit budget.

Mr. Carlin testified that base compensation levels for all types of positions (physical/craft, salaried, managerial and executives) are below the market median on average, although the Company's base compensation levels generally remain within the market competitive range (typically +/- 10 percent of the median for hourly/craft employees and +/- 15 percent for other employees). The Company's target annual incentive compensation has fallen relative to market because these levels are calculated as a function of base compensation. Partially as a result, the Company's target TCC (base pay plus target annual incentive compensation) is also below market median on average for these types of positions.

Mr. Carlin stated that the design of the Company's compensation programs and, specifically, its annual and long-term incentive compensation programs, was reasonable and appropriate. According to Mr. Carlin, these programs are necessary to ensure that the Company is able to attract, retain, and motivate the employees needed to efficiently and effectively provide electric service to its customers. The compensation that the Company provides, including annual and long-term incentive compensation, is a just, reasonable and prudent cost of doing business. It is market competitive on a base pay, target TCC, and target TDC basis. Annual and long-term incentive compensation is earned based on performance and is shown to be market competitive.

The Company's employee incentive compensation is not a "Bonus" nor an additional expense to PSO's customers above the cost of providing market competitive compensation through base pay alone. Most importantly, the fact that the Company's total employee compensation is fair and reasonable based on the market comparison studies provided has not been questioned. Therefore, it is fair and reasonable to include in the Company's cost of service, the cost of this reasonable and customary market based employee compensation, including the target level of annual and long-term employee incentive compensation as well as base pay.

Mr. Carlin stated that rather than paying market competitive compensation through higher fixed base pay, the Company provides lower fixed base pay, and an opportunity to earn up to the market competitive level of compensation, only if performance goals are achieved. By directly tying annual incentive compensation to a tightly controlled annual budgeting process for operation and maintenance and capital expenditures, these goals instill financial discipline in the employee population and encourage strong performance in other areas. This directly reduces costs for customers and it helps create a culture of high performance that provides many other direct and indirect benefits to customers. Specific annual dollar targets are developed each year at levels that require PSO to find efficiencies and otherwise reduce costs to achieve its financial targets. At the same time, PSO must also achieve its ICP customer service goals (e.g. SAIDI for electric system reliability, and customer satisfaction as measured by J. D. Powers surveys). This balancing effect of the various targets encourages all employees to improve productivity to achieve customer satisfaction and other goals with limited financial resources and, thereby improve the customer experience.

The State of Oklahoma's Office of Management and Enterprise Services, Human Capital Management, has adopted a similar incentive compensation system that uses "Performance-based adjustments" which may be earned by employees in addition to a base salary as shown in Title 260: Chapter 25. The State clearly accepts that using incentive compensation to achieve performance goals can help both customers and other stakeholders. As the State of Oklahoma has recognized with their own incentive and productivity programs, the Company has a responsibility to attract and retain the suitably skilled workforce that it needs to efficiently and effectively provide its services to customers.

To attract and retain the highly skilled workforce necessary to efficiently and effectively provide safe and quality electric service to customers requires market competitive compensation. Without this, we cannot attract such employees in the first place and employee turnover (and turnover related costs) would increase, particularly among the higher performing employees who are most capable of finding a better opportunity. In summary, using incentive compensation as part of a market competitive compensation package serves the interests of customers, as well as other stakeholders, and it is reasonable and appropriate to include the target value of the associated costs in the Company's cost of service.

Gary C. Knight

Mr. Gary C. Knight, who is employed by Public Service Company of Oklahoma (PSO), as Vice President-Generating Assets, testified on behalf of PSO.

According to Mr. Knight, PSO owns and operates seven plants consisting of 19 units that are located within the state of Oklahoma. In addition, PSO operates and owns approximately 15.6% of, 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 4,431 MW. Based on fuel type, PSO's generating units are approximately 23% (or 1,039 MW) coal-fired capacity, and 77% (or 3,392 MW) natural gas-fueled capacity. A table summarizing the generating units was provided in EXHIBIT GCK-1.

Mr. Knight described the relationship between the PSO generation fleet and the AEPSC organization. Mr. Knight stated that AEPSC provides PSO generation with executive leadership, management direction, and staff support, with both PSO and AEPSC focused 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.

Mr. Knight described the specific AEPSC groups that provide generation-related services to PSO, and the services they provided. According to Mr. Knight, five organizations report through the AEPSC Executive Vice President of Generation and are responsible for providing services and support to PSO. These five groups are Fossil & Hydro (FH) Generation, Engineering Services (ES), the Projects, Controls, and Construction group (PCC), Regulated Commercial Operations (RCO), and Business Services.

Mr. Knight described the five organizations as follows:

- The Fossil & Hydro Generation organization is involved directly in the operation and maintenance of the power plants in each of the AEP operating companies. This group is comprised of the individual operating company Generating Asset Vice Presidents and the Fossil & Hydro Generation Senior Vice President. The operating company vice presidents operate as an interface between the operating company and the Generation organization. This group is also responsible for fleet optimization, operational excellence, technical skills training and field services.

- Engineering Services provides technical expertise for complex, highly involved problems and facilitates the sharing of knowledge by acting as a data-clearing house. ES is responsible for new unit design criteria and the design and engineering of proposed changes to existing power plant equipment and systems. This group also maintains design basis information for the plants and establishes and communicates technical recommendations and requirements to all of the plants across the system. The ES organization is typically responsible for projects costing more than $750,000, but less than $5,000,000. Sharing internal resources avoids paying a premium for the services of third-party engineering firms. It also allows for guidance in the selection of vendors allowing PSO to locate vendors with quality records of accomplishment and reasonable market cost structures.

- Projects, Controls, and Construction is responsible for the planning and execution of larger capital projects at the power plants. PCC typically provides project management and execution services for large capital projects - those projects greater than $5,000,000 in total cost. The PCC organization manages these projects by tracking costs, procurement, engineering, and construction activities to ensure successful execution of large capital additions. This group is also responsible for planning and estimating, as well as controlling and tracking costs, for large outages and projects.

- Regulated Commercial Operations is responsible for market operations and support (e.g. Southwest Power Pool), as well as the procurement and delivery of suitable fuels and consumable products to the PSO generating plants. RCO also manages the emissions credits of the generating fleet.

- Business Services is tasked with providing financial analyses, business planning, and contract administration at the corporate level within the Generation organization. This group, in support of PSO, is also responsible for assisting in the determination of projected useful plant lives.

Mr. Knight stated that PSO's adjusted test year generation non-fuel O&M of $79.4 million was consistent with historic non-fuel O&M levels. Mr. Knight explained that annual generation non-fuel O&M is variable and can fluctuate depending on each year's activities required to properly maintain the plants for safe and reliable operation and that the adjusted test year amount represents a reasonable level of ongoing O&M expense.

Mr. Knight explained that the test year generation O&M was adjusted for known and measurable items. Mr. Knight stated that an adjustment of $2.49 million was made to the test year generation O&M to remove non-recurring expenses. An adjustment of $1.95 million was also made to reflect the net impact of PSO's environmental compliance plan at Northeastern Power Station. Mr. Knight testified that the adjustment for Northeastern reflects both the removal of $3.80 million O&M expense associated with the retirement of Northeastern Unit 4 and the increase of $1.85 million in expense with the new equipment installed at Northeastern Unit 3. These expenses were removed from the cost of service to accurately reflect the ongoing level of generation O&M expense for PSO.

Mr. Knight provided an overview of general projects that had been added to plant in service. According to Mr. Knight, PSO added approximately $59.2 million to generation plant in service since Cause No. PUD 201300217. Of the total generation plant in service addition of $59.2 million, $33.6 million is associated with major capital projects that had a cost greater than $500,000. The remaining $25.6 million capital addition since the last rate case is associated with a combination of individual production plant blanket (PPB) capital projects, asset retirement obligations (AROs) and other capital additions.

Mr. Knight testified that to serve its customers, it is essential that PSO's fleet of coal and gas-fired units remain safe, environmentally compliant, reliable, and economical. Providing the proper levels of O&M expenditures, coupled with prudent capital investments, is necessary to maintain the PSO generation fleet so it may continue providing low-cost generation for PSO's customers. The purpose of the capital projects that PSO implemented was to comply with safety, health, or environmental requirements as well as to maintain or improve the reliability and efficiency of the PSO generating fleet.

Steven F. Baker

Mr. Steven F. Baker, Vice President of Distribution Operations for the Public Service Company of Oklahoma (PSO or Company), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Baker directs the activities of the employees and contractors who design, construct, operate, and maintain PSO's distribution system. His duties include extension of service to new customers, the safe and reliable delivery of service to our customers, and restoring service when outages occur. His responsibilities also include overseeing PSO's distribution asset management and major reliability programs, as well as the distribution system vegetation management program.

Mr. Baker's testimony addresses the distribution test year and ongoing level of operation and maintenance (O&M) expenses, supports the distribution system investments made since PSO's last rate case, and supports PSO's distribution removal costs. His testimony also addresses the American Electric Power Service Corporation (AEPSC) affiliate charges to PSO distribution during the test year and PSO's distribution reliability.

According to Mr. Baker, PSO has invested approximately $128.9 million in its distribution system beyond the investment included in the last base rate proceeding. This investment supports safety, customer growth, customer satisfaction, reliability planning, and engineering standards, in addition to complying with Commission rules. The distribution capital investment projects are necessary and reasonable to continue to provide safe, reliable, and economic service to PSO customers.

PSO's adjusted test year distribution O&M expense is approximately $49.5 million, which includes 2013 severe storm amortization expense approved in Cause No. PUD 201300217. 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.

PSO strives to manage its costs while maintaining safety, reliability and value to its customers. The PSO distribution system is managed by PSO employees along with AEPSC employees and contractors.

Charles D. Matthews

Mr. Charles D. Matthews, Managing Director Transmission West for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of Public Service Company of Oklahoma (PSO).

Mr. Matthew's testimony described the AEP Transmission organization, described the services provided to PSO by AEPSC, demonstrated the necessity and reasonableness of PSO's transmission capital additions, and supported PSO's test year level of Operation and Maintenance (O&M) expense.

According to Mr. Matthews, PSO has invested approximately $96.5 million in its transmission system beyond the investment included in the last base rate proceeding. This investment addressed increasing reliability compliance requirements, load growth for loads served by the PSO transmission system, and the continued evolution of the wholesale power market in the Southwest Power Pool (SPP). The investments for all of these transmission capital projects were necessary and reasonable, and in making these investments, it is PSO's goal that its transmission system provide reliable delivery of electric energy which does not unreasonably restrict generation output or energy transfers.

PSO's adjusted test year transmission O&M expenses were approximately $65.08 million.

The PSO transmission system is managed by the AEP Transmission business unit (AEP Transmission), which consists of PSO employees, AEPSC employees, and contractors.

C. Richard Ross

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

Mr. Ross' testimony provides information describing the Southwest Power Pool (SPP) organization and stakeholder process, the services procured on behalf of Public Service Company of Oklahoma (PSO) under the SPP Open Access Transmission Service Tariff (Tariff), and transmission cost allocation for transmission expansion planning. He explained each of various services provided by SPP including reliability coordination, tariff administration, regional scheduling, transmission expansion planning, market operations, compliance and training. Additionally, he outlined the member-driven collaborative nature of the SPP organization that is guided by a large number of stakeholder-populated committees, working groups, and task forces maintaining and developing policies to be implemented by SPP. Mr. Ross explained how both AEPSC and PSO have active participation in the SPP stakeholder groups.

Mr. Ross testified that he believed PSO's purchase of services from SPP provides benefits to PSO and its customers. According to Mr. Ross, this is possible due to a number of factors. First, Mr. Ross explained how both AEPSC and PSO have active participation in the SPP stakeholder groups, which provide oversight to the SPP transmission planning activities so that the transmission projects selected for construction are reasonable and beneficial. Second, procedures in place under the Project Cost Working Group (PCWG) provide ongoing oversight over the actual cost of SPP transmission expansion projects. Finally, there is the additional oversight available through proceedings at FERC and ongoing Regional Cost Allocation Review activities and the OCC's participation in the Regional State Committee. Mr. Ross testified that in combination these activities are an effective means for PSO to have the assurance that the cost of transmission projects built in SPP are reasonable and provide benefits to PSO's customers.

Rajagopalan Sundararajan

Mr. Rajagopalan Sundararajan, Vice President, Transmission Asset Strategy and Policy for American Electric Power Service Corporation (AEPSC) testified on behalf of Public Service Company of Oklahoma (PSO). Mr. Sundararajan is also Vice President, Transource Energy, LLC (Transource) and its four subsidiary companies.

Mr. Sundararajan provided an overview of the AEP Transmission Business Structure. According to Mr. Sundararajan, AEP Transmission Holding Company, LLC (AEPHoldco) is a wholly-owned subsidiary of AEP. AEP Transmission Company, LLC (AEPTCo) is a wholly-owned transmission subsidiary of AEPHoldco. AEPTCo serves as a holding company for AEP's seven transmission-only companies that were created to assist AEP's operating companies in developing transmission: AEP Oklahoma Transmission Company (OK Transco) and AEP Southwestern Transmission Company, Inc., both located in the SPP RTO, and AEP Appalachian Transmission Company, Inc, AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc., all located in the PJM RTO.

Mr. Sundararajan testified that AEP Transcos were created to assist AEP's operating companies by providing an additional source of capital that can be used to meet their increasing transmission capital investment needs. The electrical grid in the U.S. is facing several new demands, including the development of energy markets, and RTO transmission service needs that provide for increased demands on the existing transmission infrastructure. In addition, much of the existing aging infrastructure needs to be replaced. Prior to the creation of the RTO's, utilities built generation, distribution and transmission to serve their own load-serving needs and had interconnections with neighboring utilities for emergency needs and to sell excess energy to others and to buy lower-cost energy to serve their own customers. That is no longer the case since the issuance of FERC Order No. 888 (issued in 1996), Order No. 890 (issued in 2007) and most recently Order No. 1000 (issued in 2011), which builds on the foundation of the two previous orders.

With the advent of the RTOs, the electrical grid is now planned differently than it was historically planned to serve local load. It is now used to transmit energy within the RTOs from generators far beyond the local utility to the RTO, as well as transmit energy from the RTO to loads far beyond the local utility's, [*sic*] which has increased stress and created new needs on the electric grid. Also, new federal environmental requirements on coal-fired generation have resulted in the shut-down of many such generating plants in the U.S., which has increased demands on the transmission system to maintain a stable and reliable electrical grid.

In response to these demands, AEP's operating companies are facing increased capital needs for their generation and transmission, in addition to their distribution needs to serve their retail loads. AEP created the Transcos to provide a financial "relief valve" to construct the increased transmission facilities on behalf of its operating companies that were required in this new environment. This enables the operating companies to maintain viable financial ratings while meeting their distribution, generation and existing transmission needs.

According to Mr. Sundararajan, since OK Transco began operations in 2010, it has invested approximately $346 million in transmission assets, which otherwise would have been invested by PSO. Over the next three years, OK Transco plans to invest approximately $392 million in transmission projects in Oklahoma. Current OK Transco projects and their benefits, in addition to planned future year OK Transco investment values, are described in PSO witness Robinson's Direct Testimony.

Mr. Sundararajan further testified that as one of seven AEP transmission-only companies, the OK Transco was specifically formed to provide an alternate vehicle to construct, own, and operate necessary transmission facilities in PSO's service territory to preserve PSO's financial strength and increase PSO's financial flexibility. PSO has generation, distribution, and transmission system needs that require significant capital investments and the OK Transco serves as a relief valve for PSO's transmission capital needs as discussed below.

Mr. Sundararajan noted that many transmission-only companies have been developed by utilities based on the opportunity for transcos to serve as a financial "relief valve" as described above. This trend has expanded due to incumbent utilities losing the right of first refusal (ROFR) in constructing certain regional projects within their own service territories. He also provided a complete list of approved SPP Qualified RFP participants for 2015.

Mr. Sundararajan provided an overview of FERC Order No. 1000 and that one of the most significant provisions is the removal of the federal ROFR for incumbent utilities within tariffs and agreements for certain regional transmission projects. With the elimination of the federal ROFR in RTO tariffs for incumbent utilities to construct certain regional transmission projects within their own service territories creates an opportunity for any qualified entity to build and own regional transmission facilities. Mr. Sundararajan further testified that FERC

Order No. 1000 builds on the foundation of FERC Order No. 888 and Order No. 890 and contains the following key elements:

a) Requires each public utility transmission provider to participate in a regional transmission planning process;

b) Requires each public utility transmission provider to develop its transmission planning processes to consider and include public policy requirements;

c) Removes the feral right of first refusal within tariffs and agreements with certain exceptions;

d) Directs regions to develop interregional transmission plans with neighboring regions;

e) Directs regions to develop regional cost allocation methodologies for cost allocation; and

f) Directs regions to develop interregional cost allocation methodologies for new transmission facilities located in two or more neighboring transmission planning regions.

Mr. Sundararajan explained that the OK Transco would not respond to FERC Order No. 1000 competitive solicitations as the OK Transco was formed to invest in projects within the PSO footprint that might have otherwise been owned by PSO, and a separate entity, Transource, was formed as a joint venture to develop the regional projects to respond to FERC Order No. 1000 competitive processes in SPP, PJM, and MISO. Transource will compete for projects in the SPP and if it is successful, Oklahoma customers will benefit as Transource will have been awarded the project by SPP as a result of the competitive request for proposal process. PSO will still invest in its transmission system as well; however, those needs are reduced by the OK Transco. Reliability projects required within three years, projects required for transmission service, and rebuilds SPP has determined as needing to be upgraded will be the responsibility of the incumbent transmission owner, as will projects required for generation interconnections that were not a part of FERC Order No. 1000 competition.

<u>K. Shawn Robinson</u>

Mr. K. Shawn Robinson is employed by American Electric Power Service Corporation (AEPSC), one of several subsidiaries of American Electric Power Company, Inc. (AEP) as Director – West Transmission Planning for AEPSC.

According to Mr. Robinson, his testimony supported an overview of the need for and the costs and benefits of the transmission capital projects constructed and owned by OK Transco to support PSO's request for recovery of costs under the Southwest Power Pool (SPP) Federal Energy Regulatory Commission (FERC)-approved SPP Open Access Transmission Tariff (SPP OATT or Tariff). He also describe [*sic*] SPP's transmission expansion planning (STEP) processes to assess transmission needs resulting in projects that are beneficial and necessary for the SPP region, including PSO's Oklahoma customers. Mr. Robinson's testimony:

- Discussed how the OK Transco projects facilitate a more robust and flexible transmission system in Oklahoma that enhances system reliability and provides access to lower energy costs for Oklahoma customers;

- Provided a 3-Year Forecast for OK Transco project investments;

- Described the major factors that drive the need for new transmission investment constructed by the OK Transco including the federal, RTO and AEP reliability standards;

- Discussed major OK Transco projects and the process used by AEP to determine which AEP entity constructs and owns transmission assets; and

- Provided the OK Transco transmission capital investments recovered under the SPP OATT since PSO's last Base Rate Case.

John O. Aaron

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

According to Mr. Aaron, his testimony presents and supports 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. His testimony also supports the pro forma adjustments made to the test year customer, revenue, and sales volume data as well as the tariff to recover PSO's environmental compliance costs through an Environmental Compliance Rider (ECR).

Mr. Aaron testified that 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 PSO's SPP Transmission Cost (SPPTC) tariff provides for the recovery of SPP Base Plan costs (Schedule 11 of the SPP OATT) associated with projects constructed by non-PSO transmission owners within SPP, excluding costs of projects constructed by Oklahoma Transmission Company, Inc. (OK Transco) and changes the billing to the industrial major rate classes to a demand basis rather than a kWh basis. He described the categories of information that supported the reasonableness of the SPP expenses recovered through the SPPTC tariff and stated that PSO is not requesting to change its SPPTC tariff in this base rate proceeding.

Mr. Aaron testified that the ECR tariff, attached as Exhibit JOA-8, provides for the recovery of eligible environmental costs using the same methodology as if the costs had been included in PSO's base rate revenue requirement. Eligible costs in this filing are capital expenditures associated with the addition of environmental controls installed at Northeastern Unit 3 and Comanche Power Station Power Plants as discussed by PSO Witness David Sartin.

The ECR factors are calculated by allocating PSO's total company environmental compliance revenue requirement to the Oklahoma retail jurisdiction and major rate classes using the production allocation factors developed in this filing. The class revenue requirement was then divided by the billing determinants for each major class to determine the ECR factor. The factors will apply to kWh usage for the residential and commercial major rate classes and will apply to maximum billing demands (kW) for the industrial major classes. PSO plans to make the rate effective for all retail customers with the first billing cycle of March 2016. The Northeastern Unit 3 environmental facilities are expected to be placed in service in February 2016. The ECR factors will remain in effect until the facilities are included in PSO's retail base rates.

In Summary, Mr. Aaron testified that the jurisdictional and class cost-of-service studies identify the embedded cost-of-service for both the Oklahoma retail and FERC jurisdictions. These embedded cost-of-service studies are based upon sound cost allocation principles, reflect all of the test year adjustments, and establish the cost responsibility for the provision of electric service to each jurisdiction and class.

PSO's Environmental Compliance Rider (ECR) provides for the recovery of eligible environmental costs using the same methodology as if the costs had been included in PSO's base rate revenue requirement.

<u>Jennifer L. Jackson</u>

Jennifer L. Jackson, Regulatory Consultant in Regulated Pricing and Analysis, part of the American Electric Power Service Corporation (AEPSC) Regulatory Services Department, testified on behalf of Public Service Company of Oklahoma (PSO or Company). Ms. Jackson's testimony explains the distribution of the proposed revenue change to all retail customer classes and presents the updated pricing for the retail rate classes based on the proposed revenue requirement for each class. Ms. Jackson sponsored the following schedules and workpapers from Section M – Proof of Revenue/Rate Design and Section N - Proposed Rate Schedules of the application package:

Schedule / WP	Description
Schedule M-1	Oklahoma Jurisdictional Pro Forma Revenue Summary
W P M-1	Fuel or Purchase Energy Factor
W P M-2	Proposed Changes in Miscellaneous Charges
W P M-3	Present and Proposed Rate Classes
W P M-4	Proof of Revenue Statement
W P M-4.1	Proof of Revenue Statement Present Rates
W P M-5	Bill Comparisons
Section N	Proposed Rate Schedules

Ms. Jackson sponsored EXHIBIT JLJ-1, the proposed revenue distribution and explains that EXHIBIT JLJ-1 was the distribution of the proposed revenue change to the retail classes. The revenue distribution details the present adjusted revenues by class along with the equalized increase for all classes, the final target revenue change by class, and the base and total bill impact to the customer classes. According to Ms. Jackson's testimony, PSO is requesting a change in retail base rates of $88.9 million. PSO is also requesting to recover $44.2 million in certain environmental compliance costs, either through a rider mechanism or through base rates. PSO's total request, including the environment compliance costs, is $133.1 million.

In addition to the rate change proposal described above, PSO has identified $39.2 million of annual Fuel Adjustment Clause items including the cost of replacement power of $35.2 million and consumables of $4 million, relating to its environmental compliance plan. These fuel-related items have been incorporated into EXHIBIT JLJ-1 in order to show the total impact of all proposed changes related to this filing and a future fuel factor filing.

Ms. Jackson's testimony summarizes the current rate structures of PSO. 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, 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.

Ms. Jackson testified that PSO was proposing to continue the basic principles of its rate design recently approved by this Commission and is not proposing any structural changes to its rate schedules.

Ms. Jackson testified that PSO was proposing to distribute the total system average revenue requirement change needed to achieve a system average return of 7.60 percent; a

16.25% change in base rates, equally to all customer classes. At an equalized return (also called unity), the revenue requirement and the proposed rates for each customer class are designed to recover the class responsibility for the cost to serve each respective class. According to Ms. Jackson, PSO is not proposing an equalized return for all classes. While unity for all classes is the ideal, customer impact concerns for the residential and lighting classes have consistently prevented the full implementation of rates based on an equalized return. As can be seen in the EXHIBIT JLJ-1 revenue distribution, which reflects the equalized cost-of-service study, the residential and certain lighting classes would be required to receive large increases in base rates under a unity revenue distribution.

Included in Ms. Jackson's testimony is Table 1 which indicates the percentage change in base rates needed to bring each class to an equalized return, the percentage change in base rates proposed by PSO, and the proposed total bill change when current fuel, current rider revenues, the proposed environmental costs and the estimated future change in fuel are included with the base rate change 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
Residential	22.33%	16.25%	14.82%
Commercial & Small Industrial	7.52%	16.25%	13.35%
Large Power & Light SL3	13.67%	16.25%	11.36%
Large Power & Light SL2	14.73%	16.25%	11.35%
Large Power & Light SL1	17.69%	16.25%	10.66%
Lighting	23.15%	16.25%	13.81%
Total Retail	16.25%	16.25%	13.56%

Ms. Jackson's testimony briefly describes the PSO retail rate schedules for the major classes.

- Limited Usage Residential Service (LURS) and Residential Service (RS) for service to residential customers;

- Limited Usage General Service (LUGS) and General Service (GS) for small commercial loads;

- Power & Light Service (PL) and Primary Non Demand (PND) for larger commercial and small industrial loads;

- Large Power & Light (LPL) for service to primary, primary substation, and transmission voltage large industrial and commercial customers billed on demand;

- Municipal Pumping (MP) closed service to municipal pumping loads;

- Lighting Service (Private, Security, Area, Municipal, and Parkway Lighting); and

- Time-of-Day (TOD) rate schedules that are currently in effect for RS, LUGS, and GS customers.

Ms. Jackson testified that the proposed revenue distribution shown on EXHIBIT JLJ-1 guided the percentage change to each class. The proposed increase to the classes is applied to base rates. Base rate charges include base service charges, energy charges, demand charges (including kVAR charges), and any minimum bill charges. A percentage change is applied to demand charges, base service charges and minimum bill charges, depending on each class's rate schedule.

Ms. Jackson testified that when the fuel component is included, the total bill change is lessened based upon the amount of total fuel revenue associated with each class. The total bill change is also impacted by the fact that PSO has additional service riders and is asking for recovery of environmental costs and is estimating a change in future fuel.

EXHIBIT JLJ-1 showed the base percentage change and the corresponding total bill change (base plus the current fuel, current riders, the proposed environmental costs, and the estimated changes in future fuel) to each class. The present and proposed base rate changes and resulting percentage changes for each rate class can be found in Section W/P M-4.1. Ms. Jackson's testimony described the proposed base rate changes associated with all of the rate classes.

Ms. Jackson's testimony recommended approval of the rates as filed because the proposed rates are based on the cost-of-service study results and the proposed revenue distribution and the base rate changes achieve the revenue required from each class according to the proposed revenue distribution, EXHIBIT JLJ-1. The Rate Design W/P M-4.1 details the present and proposed rates for each rate component of each rate schedule along with the resulting proof of revenue. W/P M-5 showed the current and proposed typical bills for the residential and commercial rate classes including all changes requested by PSO. Section N provided the proposed rate schedules with all of the changes proposed in PSO's filing, including the changes to the rate schedules.

Summaries of Responsive Testimony of United States Department of Defense and All Other Federal Executive Agencies

Lafayette K. Morgan, Jr.

On October 14, 2015, Lafayette Morgan, Jr. filed Responsive Testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") to review the General Rate Filing submitted by Public Service Company of Oklahoma ("PSO" or "Company") and to determine the level of revenues that PSO should be authorized in this proceeding. Mr. Morgan addresses several revenue requirement issues. In total, Mr. Morgan determined that the Company has a revenue deficiency of $23,116,970 for test year ended January 31, 2015. This represents a decrease of $60,711,672 compared to PSO's requested increase of $83,828,642. This is the amount by which revenues exceed those required to generate an overall rate of return of 6.86 percent after accounting for the DoD/FEA adjustments to PSO's claimed rate base and operating income. The return of 6.86 percent represents DoD/FEA witness Maureen Reno's finding regarding the Company's overall rate of return on behalf of the DoD/FEA. Mr. Morgan documents and explains each of his proposed adjustments to rate base and operating income leading to his recommended test year revenue increase.

Post-test Year Adjustments

Mr. Morgan uses PSO's proposed test year ended January 31, 2015, as the basis for determining PSO's rate year revenue requirements. Mr. Morgan notes that the Corporation Commission of Oklahoma ("Commission") typically has allowed an update to the test year to capture actual activity through six months after the end of the test year. However, the Company has proposed to recover several post-test year investments that exceed the six-month period in either base rates or through the Environmental Cost Rider ("ECR"). Those investments are as follows:

1. The Northeastern Unit 3 ("NE 3") environmental net investments of $178 million.
2. The Comanche Generating Station ("Comanche") environmental control equipment and facilities of $43.9 million.
3. Depreciation expense on NE 3 and Comanche environmental investment of $18.8 million.

Mr. Morgan is recommending that the post-test year adjustments sought by the Company not be included in base rates. Mr. Morgan recommends post-test year adjustments should not be permitted because they require ratepayers to begin to pay for the costs and return on investments that the utility has not yet incurred.

Rate Base Update Adjustment

PSO has reflected plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT"), working capital, and other deferred debits and credits based upon the test year ended January 31, 2015. Mr. Morgan recommends an adjustment to various components of the rate base through the six months ended July 31, 2015. On Schedule LKM-6, Mr. Morgan presents his adjustment, which reduces rate base by $74,489,310.

Operating Revenues Adjustment

PSO has adjusted sales to derive base revenues by removing the non-base revenue components and adjusting the base rate revenues to reflect customer growth and weather normalization. Mr. Morgan is recommending an adjustment to operating revenue to annualize revenues based upon the average revenue per customer and the number of customers as of July 31, 2015. On Schedule LKM-7, Mr. Morgan presents his adjustment to Operating Revenue resulting in an increase in test year revenue of $2,339,704.

Labor Expense

PSO developed its test year base labor claim by annualizing its test year end base payroll. On Schedule LKM-8, Mr. Morgan presents an adjustment to Labor Expense based on PSO's annualized payroll as of July 2015. This adjustment reduces payroll expense by $171,890 and payroll taxes by $13,150.

Employee Benefits Expense

PSO's claim for employee group insurance expense was determined by adjusting the test year level of expense by annualizing only the month of January 2015. Mr. Morgan disagrees with this approach because there is a wide variation in the test year monthly employee benefits costs. Mr. Morgan calculated the cost per participant of $1,073 and applied that amount to the number of participants as of July 2015 to derive the annualized employee group insurance expense. This calculation results in a reduction in the expense by $864,257 on Schedule LKM-9.

Ad Valorem Taxes

According to Mr. Morgan, ad valorem taxes are calculated based upon applying the tax rate to the net investment in plant. As a result of the adjustment that he made to update rate base, the net plant investment has changed. Therefore, Mr. Morgan made an adjustment to reduce the level of ad valorem taxes by $1,158,398 on Schedule LKM-10.

Interest Synchronization

Mr. Morgan's interest synchronization adjustment decreases the interest deduction by $231,166 to reflect Ms. Reno's capital structure and the DoD/FEA rate base adjustments. This resulted in an increase in the combined income taxes by $89,413.

Larry Blank

On October 14, 2015, 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 proposed ratemaking treatment for Northeastern Station Unit 3 ("NE 3") and Northeastern Station Unit 4 ("NE 4") in the direct case of Public Service Company of Oklahoma ("PSO") for Cause No. PUD 201500208. Dr. Blank testifies on the following issues:

- The depreciation life for NE 3 and NE 4 should not change, and should continue with the depreciation schedule in place at the time PSO entered into its settlement for the environmental compliance.

- The risk associated with the operation and cost recovery of NE 4 will be greatly reduced once it is retired, therefore PSO's proposed ratemaking treatment for NE 4 will result in over-recovery of return and undue enrichment of the Company. To avoid this over-recovery, Dr. Blank recommends that PSO create a Regulatory Asset Rider for NE 4 to collect a fixed, levelized annual amount of $6,331,684 over the next 24 years, and provides the specific parameters under which this amount is calculated.

- Based on the issues described above, Dr. Blank's testimony recommends four separate adjustments to the PSO proposed rate base and revenue requirement for base rates. Specifically, Dr. Blank recommends the following adjustments for the base rate revenue requirement calculations proposed by PSO:

- Removal of $181,737,467 from gross plant in service associated with NE 4;
- Removal of $102,791,645 from accumulated depreciation reserve associated with NE 4;
- Removal of $2,627,449 from annual depreciation expense (at current depreciation rates) associated with NE 4; and
- Removal of $12,811,352 to reverse the depreciation expense adjustment on NE 3 and NE 4 proposed by PSO.

Depreciation Schedules for Northeastern Units 3 and 4

As part of a settlement agreement with the U.S. Environmental Protection Agency ("EPA") and others, PSO has proposed to install the necessary environmental control equipment at NE 3 and continue operating that unit until retirement in 2026. PSO proposes to retire NE 4 early in 2016. PSO's Environmental Compliance Plan ("ECP"), which includes the early retirement of NE 3 and NE 4, should be viewed as a plan that will benefit customers, the State of Oklahoma, and the United States for many years beyond 2026. The expected life of NE 3 and NE 4 at the time of the environmental settlement extended until 2040, and it is expected that the environmental benefits from the early retirement of these coal-fired units anticipated by the parties to that agreement also extend to 2040, and beyond. Dr. Blank testifies that the environmental benefits associated with the decisions regarding NE 3 and NE 4 should be recognized in deciding what is just and reasonable for cost recovery and ratemaking. When determining appropriate depreciation rates, it is important to consider the matching cost recovery with beneficiaries through time. Therefore, Dr. Blank testifies that the Oklahoma Corporation Commission ("OCC") should require the continued use of the currently approved depreciation rates for NE 3 and NE 4 because the decision to allow for these plant investments and retirements was based on cost-effectiveness evaluations that relied on current depreciation schedules. The reversal of PSO's proposed adjustment to depreciation rates of both NE 3 and NE 4 is consistent with Dr. Blank's finding that the depreciation schedules should remain as they are currently. The reversal of the PSO proposed change to depreciation results in a reduction in revenue requirements of $12,811,352.

Remove Northeastern Unit 4 from Rate Base and Creation of a Regulatory Asset

PSO proposes to change the depreciation life on NE 4 and keep the net plant in rate base after the unit is no longer providing electricity service. Dr. Blank testifies that PSO's proposal to continue traditional ratemaking for NE 4 after it no longer provides electric service is inappropriate and will result in excess return for two reasons. First, it will allow PSO to continue earning a return on the current net plant in service without accounting for the accrual of accumulated depreciation. Second, once NE 4 is retired, the risk associated with that plant and its cost recovery is no longer comparable to the risk of capital investments associated with remaining plant still in service with the Company. Subsequently, Dr. Blank finds that the planned closure of NE 4 warrants a Regulatory Asset Rider due to the reduced risk associated with cost recovery for that generation unit and PSO's proposed ratemaking treatment subsequently results in an over-recovery of return. Dr. Blank calculates that PSO will realize up to $37.6 million in undue return over the next ten years if the Company's proposal is accepted. Dr. Blank proposes that NE 4 should be removed from base rates and recovered through a special rider cost recovery mechanism at an annual levelized amount equal to $6,331,684. The net impact of the rate base adjustments and depreciation expense adjustment to remove NE 4 and the alternative creation of an NE 4 Regulatory Asset Rider is an approximate $9.7 million reduction in revenue requirement relative to PSO's filed application.

<u>Adjustment to the Company's Proposed Revenue Requirement</u>

The combined result of Dr. Blank's testimony recommendations would be an approximate $22.5 million reduction in revenue requirement relative to that proposed by PSO.

<u>Maureen L. Reno</u>

Ms. Maureen L. Reno filed Responsive Testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") on October 14, 2015, in Cause No. PUD 201500208. Ms. Reno, who is employed as an independent consultant, has 15 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 201500208. In her development of her recommendations, 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 different than that presented by the Company's cost of capital witness, Mr. Robert B. Hevert, to calculate an estimate of the Company's cost of equity.
- 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").
- Mr. Hevert's estimation of a flotation cost adjustment and demonstration of why that adjustment is not appropriate in this case.
- A review of the Company's proposal to include environmental compliance costs into base rates or to recover such costs through an Environmental Compliance Rider ("ECR").

Capital Structure and Overall Rate of Return

Ms. Reno accepts PSO's proposed cost of long-term debt of 4.92 percent, but she disagrees with the Company's proposed capital structure of 48 percent equity and 52 percent long-term debt and cost of common equity of 10.5 percent. Ms. Reno suggests this recommendation cost of equity is overstated due to Mr. Hevert's use of inputs with an upward bias, particularly his reliance on high earnings growth rates and improper use of Commission-authorized returns when calculating his equity risk premium. She also disagrees with PSO's proposed hypothetical capital structure because it is not based on test-year and *pro forma* capital amounts. Requesting that the Commission allow a hypothetical capital structure based on the premise that the Company may temporarily, and at some future time, withhold dividends to parent company AEP is not a reasonable basis for setting the ratemaking capital structure in this case. Her cost of capital recommendations can be summarized as follows:

Capital Item	Percent	Pre-Tax Cost	Return
Long-term Debt	55.56%	4.92%	2.73%
Common Equity	44.44%	9.30%	4.13%
Total Cost of Capital	**100.00%**		**6.86%**

Ms. Reno recommends an overall allowed rate of return of 6.86 percent, based on an ROE of 9.3 percent, an embedded cost of long-term debt of 4.92 percent, and a capital structure comprised of approximately 56 percent long-term debt and 44 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 growing national economy, fear of slow economic growth overseas and deflation in energy markets have caused the Federal Reserve to delay increasing 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. Hevert's proxy group, minus Black Hills Corporation, Southern Company, and TECO Energy, Inc. She uses variants of the Single-Stage and Three-Stage DCF models and the CAPM to form the basis of her recommendation of 9.3 percent ROE for PSO, which is the midpoint of her range of 9.0 percent to 9.6 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 ending September 25, 2015. She then adds the dividend yield to each company's growth rate. In addition to employing expected earnings growth for the growth rate, as the Company's witness does, she uses expected dividend growth, expected book value growth, and sustainable growth rates because investors consider other information to assess risk in addition to earnings growth. Her range of Single-Stage DCF results are 8.15 percent to 9.17 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 to a rate of 4.5 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 8.25 percent to 9.35 percent.

Ms. Reno disagrees with Mr. Hevert's assertion that ROE estimates resulting from DCF-based methods are unreliable due to the nature of the industry's price/earnings ("P/E") ratios. Mr. Hevert believes that since DCF-based methods rely on stock prices and because P/E ratios have been above historical levels, DCF-based results are unreliable. Recent market evidence shows, however, that utility stock prices are experiencing a correction. Ms. Reno shows that utility asset valuations fluctuate over time but remain in a consistent range. Mr. Hevert merely disagrees with the results of the DCF due to the historically low cost of capital. The DCF has been widely used by regulatory agencies to identify reasonable ROEs for decades, regardless of whether the cost of capital is low or high.

Ms. Reno's third cost of equity model is the CAPM, which includes three components—the risk-free rate, beta, and the risk premium. For the risk-free rate, Ms. Reno uses a one-month average of the yields on 30-year U.S. Treasury bonds for the period ending September 25, 2015. She multiplies Value Line betas for each proxy group company by her equity risk premium. To estimate the risk premium, she measures the return differentials between common stocks and 30-year Treasury bonds. Her CAPM result is 9.61 percent and is the maximum of her recommended ROE range of 9.6 percent.

Flotation Cost Adjustment

Ms. Reno disagrees with Mr. Hevert's adjustment for flotation costs because the past flotation costs incurred by AEP, the parent company, should not be borne entirely by PSO ratepayers. In addition, she testifies that there is no need to include such flotation costs in base rates being set in this case because there is no indication of a public issuance of common stock by AEP (and therefore the incurrence of flotation expense) for the foreseeable future.

Environmental Compliance Cost Risk and the ECR

Ms. Reno's testimony addresses PSO's efforts to mitigate environmental cost recovery risk through its proposed ECR. Since PSO is requesting an alternative cost recovery method to recover prudently incurred costs from customers so that the benefits of new environmental controls going into service match the recovery of revenues from customers, PSO reduces regulatory lag for these costs, thereby reducing PSO's risk going forward. Since Ms. Reno's analysis incorporates risk associated with not having such a rider, then upon the Commission granting approval for the rider, she recommends the Commission consider an ROE lower than her recommendation of 9.3 percent but greater than the lower portion of her range of 9.0 percent.

Conclusion

Ms. Reno recommends that the Commission authorize an overall rate of return of 6.86 percent, using the test-year and *pro forma* adjusted capital structure that incorporates a cost on long-term debt of 4.92 percent and an allowed ROE of 9.3 percent. Her recommendation lies within the range of 9.0 percent and 9.6 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. Her recommendation is also in line with recent Commission-approved returns in other jurisdictions.

Summaries of Responsive Testimony of Wal-Mart Stores East, LP, and Sam's East, Inc.

Steve W. Chriss

Steve W. Chriss filed Responsive Rate Design and Cost of Service Testimony on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., (collectively "Walmart"). Mr. Chriss is Senior Manager, Energy Regulatory Analysis, with Wal-Mart Stores, Inc.

Walmart operates 133 retail units and employs 33,561 associates in Oklahoma. In the fiscal year ending 2015, Walmart purchased $677.7 million worth of goods and services from Oklahoma-based suppliers, supporting 18,438 supplier jobs. Walmart has 47 stores 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) At the Company's proposed revenue requirement, the Commission should allocate revenue using the following steps:

   a. For classes that, per the Company's cost of service study results, are paying rates below cost and should receive an above-average increase, increase the class base rate revenue by 1.1 times the system average increase of 16.25 percent;
   b. If step 1 results in a revenue requirement increase higher than required for a class to pay cost-based rates, cap the increase to that class at the cost-based level; and
   c. Allocate the remaining revenue requirement to the remaining classes per each class' contribution to present base rate revenues.

2) If the Commission determines that the appropriate level of revenue requirement is lower than the level proposed by the Company, the Commission should use the allocation methodology I propose above but increase the multiplier as appropriate to ensure that the rates for each class can be moved as close as possible to cost of service.

3) If the Commission approves an Environmental Compliance Rider, Walmart does not oppose the Company's proposed rate design for the rider.

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

Jacob Pous

My name is Jacob Pous and my business address is 1912 W Anderson Lane, Suite 202, Austin, Texas 78757.

I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI"). A copy of my qualifications appears as Appendix A.

DUCI is a consulting firm located in Austin, Texas with an international client base. The personnel of DUCI provide engineering, accounting, economic, and financial services to its clients. DUCI provides utility consulting services to municipal governments with utility systems, to end-users of utility services, and to regulatory bodies such as state public service commissions. DUCI provides complete rate case analyses, expert testimony, negotiation services, and litigation support to clients in electric, gas, telephone, water, sewer, and cable utility matters.

Appendix A also includes a list of proceedings in which I have previously presented testimony. In addition, I have been involved in numerous utility rate proceedings that resulted in settlements before testimony was filed. In total, I have participated in well over 400 utility rate proceedings in the United States and Canada. Also worthy of note is that I have testified on behalf of the staff of six different state regulatory commissions and one Canadian regulator, and been asked to speak to the National Association of Regulatory Utility Commissioners ("NARUC") on several occasions regarding the topic of depreciation.

I am a registered professional engineer. I am registered to practice as a Professional Engineer in the State of Texas, as well as other states.

My recommendations are made on behalf of Oklahoma Industrial Energy Consumers ("OIEC"), and Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively "Wal-Mart").

The purpose of my testimony is to address Public Service Company of Oklahoma's ("PSO" or the "Company") depreciation request as filed before the Corporation Commission of the State of Oklahoma ("Commission") in Cause No. PUD 201500208.

The Company retained Mr. Spanos of Gannett Fleming to develop a depreciation study based on plant as of December 31, 2014 ("2014 Study"). The 2014 Study reflects an annual depreciation accrual of $139,877,572 or a $46,661,823 increase based on plant as of December 31, 2014. Whether based on statements made by Mr. Spanos in other proceedings or realistic expectations of changes between studies, a 50% increase in depreciation expense due to a change in rates, not plant, should be considered extreme. Moreover, requested changes of this magnitude must be well explained, justified and supported. Based on my review of the requested increase, the request lacks adequate explanation, and most certainly is not justified or supported.

The Commission should order the Company to provide a complete, detailed and fully documented depreciation study in support of its various life and net salvage parameters, by account, in its next case. It must be emphasized that the underlying concept behind the recommendation for a complete, detailed and fully documented depreciation study is not tied to the quantity of information provided, but the quality of the information. It is recognized that the Company provided hundreds of pages of depreciation related material in this case, unfortunately the critical items of information, assumptions, and supporting documents that identify how and why specific parameters were proposed were not provided.

I have performed an independent analysis of the 2014 Study for all functions other than the distribution function. Based on my analyses, I have identified numerous problems with the Company's depreciation request that require adjustment. The overall impact of my recommendations are set forth on Exhibit (JP-1). The test year impact of my recommendations will be reflected in the revenue requirement testimony submitted by OIEC witness Mr. Garrett. A brief synopsis of each major area of adjustment I recommend follows.

- **Northeastern Units 3 & 4 Life Span** – The Company proposes a 2026 capital recovery date for the investment in Northeastern Units 3 & 4. The proposed 2026 date does not correspond to the retirement date set for Unit 4, as well it should not. Given the underlying basis for the change in expected life spans for the units, the more appropriate capital recovery date should be 2040. Recognition of a 2040 capital recovery date for Units 3 and 4, along with corresponding retirement date related impacts on interim retirements and net salvage, result in an approximate $10 million reduction in annual depreciation expense based on plant as of December 31, 2014.

- **Production Plant Net Salvage** – The Company proposes various negative net salvage values for its steam and other production generating facilities. These values are based in part on studies presented by Mr. Meehan of Sargent & Lundy, LLC ("S&L"). The S&L studies are updates of prior estimates for future demolition of the Company's generating units dating back to 2008. The results of the S&L studies were then inflated by Mr. Spanos for as many as 44 years into the future without discounting such values back to the present, and the estimated impact of interim net salvage was applied. Based on the elimination of contingencies and the escalation of estimated costs in to the future without discounting cost back to a net percent value, and a reduction in the level of estimated interim net salvage, depreciation expense is reduced by approximately $6 million based on plant as of December 31, 2014.

- **Interim Retirements** – The Company proposes a new method of calculating interim retirements for its plant. The Company's new method results in a significant increase in estimated interim retirements compared to the method and results that it proposed and the Commission approved in prior depreciation studies and rate cases. Since higher levels of estimated interim retirements results in a shorter remaining life, and thus higher depreciation expense, the Company's new methodology artificially increases depreciation expense. There are several problems associated with the Company's proposed new method. Relying on the Company's long established interim retirement methodology, as well as interim retirement ratios previously adopted by the Commission for the Company, results in an approximate $100,00 reduction in annual depreciation expense for plant as of December 31, 2014.

- **Production Plant Interim Net Salvage** – The Company proposes excessive negative net salvage levels for the higher level of interim retirements that it projects. Adjusting only the Company's proposed steam plant interim net salvage level to a more appropriate level results in a reduction in annual depreciation expense of $1,275,753 based on plant as of December 31, 2012.

- **Mass Property Life Analysis** – The Company relies on an actuarial analysis approach for estimating average service life ("ASL") and corresponding mortality dispersion pattern for mass property accounts. The Company's interpretation of the actuarial results are inappropriate and lead to artificially short ASLs for numerous accounts. Relying on more appropriate interpretation of actuarial results, and information relating to life related improvements in operation and maintenance of the system results in a $2.1 million reduction in annual depreciation expense based on plant as of December 31, 2014.

- **Mass Property Net Salvage** – The Company's proposals for several mass property accounts result in excessive levels of negative net salvage. The Company's proposals [*sic*] fails to take into account specific impacts reflected in historical data that are not indicative of future net salvage expectations. Corrections of this and other problems results in a $3 million reduction to annual depreciation expense based on plant as of December 31, 2014.

- **Combined Impact** – The combined impact of the various adjustments noted above are not simply the summation of each individual standalone adjustment. Certain adjustments are interactive. The combined impact of the various above noted issues results in a $22,361,139 reduction in annual depreciation expense based on plant as of December 31, 2014, as set forth on Exhibit (JP-1).

Summaries of Responsive Testimony of Oklahoma Industrial Energy Consumers

Mark E. Garrett

1. **Impact of OIEC's Adjustments.** In my responsive testimony, I address various revenue requirement issues identified in PSO's rate case application and provide recommendations for the resolution of these issues. I also sponsor Exhibit MG-2, setting forth the overall impact of OIEC's recommendations. In total, OIEC's recommendations result in a rate increase of $9.56M, as shown below:

Rate Increase Proposed by PSO	$ 83,828,642
OIEC Adjustments	$ (74,268,338)
Rate Increase after OIEC Adjustments	**$ 9,560,304)**

PSO's filed rate case proposes a 16.25% increase in non-fuel rates. In addition, PSO proposes a $44M increase in non-fuel rates, and an additional $39M increase in fuel costs for its Environmental Compliance Plan ("ECP"). The rate increases proposed by PSO would have a devastating impact on ratepayers, and the Commission should look for ways to mitigate the impact of the proposed rate increases.

2. **PSO's ECP Recovery Request.** The Company seeks to include $212 M in rates for plant associated with the ECP that will be placed in service in April 2016, either by extension of the rate base period to April 2016, or by implementing a rider to recover these costs. I have not included the ECP costs in rate base because the assets were not in service by July 31, 2015. I know of no example where this Commission has allowed a utility to go beyond the statutorily

prescribed 6-month cut-off to include assets in rate base [sic] such as these. I will address PSO's alternative proposal for rider treatment of the ECP costs in my Rate Design testimony filed October 23, 2015.

3. **Rate Base and Accumulated Depreciation Adjustments.** I propose adjustments to update Plant in Service and Accumulated Depreciation to PSO's actual levels through July 31, 2015, the six-month cut off period. The adjustments to PSO's actual investment levels at July 31, 2015, are set forth in Exhibit MG-2.1 of my Testimony.

4. **Accumulated Deferred Income Taxes (ADIT).** The ADIT balances are adjusted to the July 31, 2015, levels to give effect to the known and measurable increase in the deferred tax balances that occurred within six months of test year end. When additions to the investment levels in Plant in Service are recognized through the 6-month period following test year end, offsetting decreases for Accumulated Deferred Income Tax must also be recognized. OIEC's net adjustment to ADIT is $29,376,789, and is set forth in Exhibit MG-2.2 of my Testimony.

5. **Other Rate Base Adjustments.** I have updated PSO's Prepayments and Customer Deposits to reflect actual levels as of July 31, 2015, consistent with the 6-month rule in Oklahoma. The Company proposed using 13-month averages at test year end in pro forma rate base for these accounts. The use of 13-month averages would only be appropriate if these accounts reflected balances that are fluctuating month to month. These accounts, however, do not fluctuate but instead move steadily in one direction. When an account trends steadily in one direction it is more appropriate to adjust to the actual balances as of the cut-off date. The calculations supporting these adjustments are set forth in more detail at Exhibit MG-2.3 of my Testimony.

6. **Prepaid Pension Asset.** I propose reducing PSO's rate base by the balance in the prepaid pension account and increasing its operating expense by an amount equivalent to the "expected return" on the prepaid pension asset balance. This is the amount by which ratepayers benefit from these excess contributions. AEP's expected return on pension contributions is 6.0%, the amount by which the excess contributions reduce Net Periodic Pension Costs, and the amount included in rates. In effect, the net benefit to ratepayers from excess contributions is limited to 6.0%. The excess contributions are discretionary and PSO should not be allowed to earn a profit on the excess contributions it makes to the fund. Therefore, I am proposing that ratepayers pay a return on these costs that is no greater than the benefit they receive.

This treatment has been accepted by the Commission in the past including: Cause No. PUD 1991001190 [sic]; Cause No. PUD 200500151; Cause No. PUD 200600285; and Cause No. PUD 200800144. In PSO's last litigated rate case, the Company appealed the Commission's treatment of prepaid pension costs to the Oklahoma Supreme Court. The court upheld the Commission's treatment of these costs.

Three adjustments are needed: (1) to remove the prepaid pension balance from rate base; (2) to add back the accumulated deferred income taxes (ADIT) balance associated with prepaid pension costs; and (3) to increase O&M expense [sic] by an amount equal to the expected return on the prepaid balance. The adjustments are shown in the table below:

OIEC Prepaid Pension Adjustment:	**Adj.**	**ROR[1]**	**Rev. Req.**
PSO Prepaid Pension Balance in Rate Base	($93,918,297)	10.821%	($10,163,181)
ADFIT associated with Prepaid Pension	$ 32,871,404	10.821%	$ 3,557,113
Provide Cost-of-Money Return	$ 61,046,893	6.0%	$ 3,662,814
Total Impact on Revenue Requirement			**$ (2,943,254)**

The first two adjustments above are rate base adjustments and their impact on the revenue requirement is limited to the Company's overall rate of return on rate base grossed up for tax. The total revenue requirement impact of the adjustments is $2,943,254, as [*sic*] forth in Exhibit MG-2.4 of my Testimony.

7. **Capitalized Incentive Compensation in Rate Base.** Each year, PSO capitalizes a portion of its incentive plan payments, and includes them in rate base where they earn a return. The Commission has consistently excluded a portion of PSO's incentive compensation plan to the extent the plan is financially-based. In the past, the Commission has excluded 50% of PSO's short-term and 100% of the Company's long-term incentives from operating expense. 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, PSO's rate base included $49,426,251 of capitalized incentive compensation, which includes $46,642,551 of short term incentive compensation and $2,783,700 of long term incentive compensation. I propose that 50% of the capitalized short term incentive payments and 100% of the capitalized long term incentive payments be excluded from rate base. This treatment is consistent with the Commission's prior treatment of PSO's incentive expense in its prior litigated cases, PUD 200600285 and PUD 200800144. It results in an adjustment of $26,104,976, and is set forth in Exhibit MG-2.5 of my Testimony.

8. **Annual Incentive Compensation Expense.** I propose an adjustment to reduce the requested level of annual incentive expense for the portion of the incentive plans related to financial performance measures. From my review of the plans, it appears that more than 75% of the performance measures of the annual plans are tied to the Company's financial performance. As a result, I have reduced the Company's requested level of annual incentive compensation of $8,739,895 by 75%, or $6,554,921.

This adjustment is consistent with the Commission's prior treatment of the issue. In PSO's last two litigated rate cases, the Commission reduced PSO's requested annual incentive compensation by 50% based upon the extent to which the plans were tied to financial performance. PSO's 2014 Annual Compensation Plans are heavily dependent on financial performance measures, primarily as a result of the earnings Modifier, which is weighted 75%. The Company admits the funding of the incentive compensation is contingent on meeting PSO/AEP's earnings targets.

In other words, even though the Company's performance measures include some non-financial factors, the actual funding trigger for incentive compensation is Modifier, which is primarily tied to the financial performance of the Company. For example, regardless of how well the Company may perform in a nonfinancial performance measure such as safety, if the Company's earnings per share is below the stated threshold, the Modifier would be 0%, and thus, no portion of the incentive compensation would be paid. Under this incentive compensation plan, the Company's earnings level is the most significant factor in determining whether the incentive compensation [*sic*] (*see* Responsive Testimony of Mark E. Garrett, p. 16, l. 16.)

Many jurisdictions exclude some or all of the cost of incentive plans which are tied to financial performance measures [*sic*] are excluded for ratemaking purposes. 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 significantly impact earnings are outside the control of most company employees and have limited value to customers;
3) Earnings-based incentive plans can discourage conservation;
4) The utility and its stockholders assume none of the financial risks associated with incentive payments;
5) Incentive payments based on financial performance measures should be made out of increased earnings;
6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.

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 increased earnings to fund these payments. Ratepayers do not need to subsidize incentive compensation plans designed to enhance financial performance.

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.

Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance as a key component of their plans—apparently because doing so achieves the objective of increasing corporate earnings. Since the utility retains the increased earnings these plans help achieve, the incentive payments should be made from the increased earnings.

Under the Company's Plan, annual payment is uncertain. The Modifier allows AEP to significantly reduce incentive payments, or make no incentive payments at all, if the threshold

EPS goals are not met. In these situations, amounts collected through rates for incentive programs would be retained by the shareholders. In fact, in prior years, PSO has reduced incentive compensation levels based upon financial performance measures. For instance, in 2009, the Company reduced its targeted payouts by 76.9% due to financial performance shortfalls during the year. Although the Commission had included more than $4 million in rates for incentives in the Company's 2008 rate case, the Company chose not to use that money to pay incentives, but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

The truth is that for ratemaking purposes, all of the cost of the AEP/PSO incentive plans could be excluded based on the fact that these plans are overwhelmingly weighted toward company rather than customer objectives. In particular, because the earnings Modifier effectively makes incentive payments elective and dependent upon whether shareholder objectives were met each year, a significant portion should be disallowed. If, from a policy perspective, the Commission wants to allow a portion of the plan costs that purports to be representative of customer service and reliability goals, I believe no more than 25% inclusion in rates for these plans would be appropriate.

In my view, AEP/PSO will not be financially harmed if incentive compensation payments are excluded. Its incentive compensation payments are discretionary payments, limited by based on [*sic*] the Company's earnings. This ensures that the incentive payments are not made at the expense of reaching the Company's EPS goals. In those years when the EPS targets are achieved, the additional funds needed to make the incentive payments to employees will have been made available through the increased earnings that resulted from reaching these EPS goals.

The Company argues that incentives are part of an overall compensation package designed to attract and retain qualified personnel, and that the Company runs the risk of not being able to compete for key personnel if it did not offer a comparable plan. The problem with the Company's argument is that when utilities such as PSO compete with other utilities for qualified personnel, the incentive compensation plans of these other utilities are being reduced for ratemaking purposes. Thus, the Company is not put at a competitive disadvantage when its incentive compensation costs are similarly reduced.

PSO's annual Incentive Plan Payments in pro forma expense is $8,739,895. I propose a 75% disallowance, for an adjustment of $6,554,921. In addition, I propose an adjustment to remove labor attendant costs associated with the 75% disallowance of short term incentives in the amount of $362,214, as is set forth in Exhibit MG-2.5 of my Testimony.

9. <u>Long-term Executive Stock Incentive Expense.</u> Senior Managers and Executives of the Company receive additional incentive compensation through AEP's Long-Term Incentive Plan. This 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. The Company is proposing to recover $3,554,117 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.

Incentive compensation payments to officers, executives, and key employees of a utility are generally excluded for ratemaking purposes. Since officers of any corporation have a duty of loyalty to the corporation itself and not to the customers of the company, these individuals typically put the interests of the company first. Undoubtedly, the interests of the company and the interests of the customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation in which not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service.

Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders. Some utilities treat long-term executive incentive compensation costs as a below-the-line item even without a Commission order directing them to do so. Further, long-term executive incentive plans are specifically designed to tie executive compensation to the financial performance of the company. 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 Garrett Group's Incentive Survey shows 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 most states.

In Oklahoma, long-term incentives tied to corporate earnings are excluded. In PSO's last two litigated rate cases, 100% of the costs of the long-term incentive plans were excluded. Accordingly, I recommend that the cost of AEP's Long-Term Incentive Plan be excluded from rates, an adjustment to pro forma operating expense in the amount of $3,782,540. Calculations supporting this adjustment are set forth at Exhibit MG-2.5 of my Testimony.

10. <u>Supplemental Executive Retirement Plan ("SERP").</u> 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 $260,000 for 2014 and $265,000 for 2015. Retirement benefits on compensation levels in excess of these amounts are paid through supplemental plans. These 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 included in PSO's filed cost-of-service was $600,209 [*sic*], which is comprised of $156,433 for PSO and $443,776 for AEPSC.

I recommend a sharing of costs as follows: ratepayers pay for all of the executive benefits included in the Company's regular pension plans, and shareholders pay for the additional executive benefits included in the supplemental plan. For ratemaking purposes, shareholders should bear the additional costs associated with supplemental benefits to highly compensated executives, since these costs are not necessary for the provision of utility service, but are instead discretionary costs of the shareholders designed to attract, retain and reward highly compensated employees. In my experience, SERP expenses are consistently disallowed. I discuss recent decisions disallowing SERP costs in Nevada, Arkansas, and Texas. Although the Garrett Group has not conducted a comprehensive study of SERP treatment in other states, but [*sic*] I do know that SERP is disallowed in the states of Oregon, Idaho, and Arizona as well. The Oklahoma Commission disallowed 100% of AEP/PSO's SERP expense in PSO's 2006 rate case, Cause No. PUD 200600285 and in PSO's 2008 rate case, Cause No. PUD 200800144. Accordingly, I recommend an adjustment to reduce pro forma expense by SERP expenses in the amount of $600,209, set forth in Exhibit MG-2.6 of my Testimony.

11. **<u>Rate Case Expense.</u>** The Company seeks to recover $1,018,000 of estimated rate case costs in this case amortized over a two year period, at $509,000 per year. This represents a 38% increase over PSO's $740,000 estimated costs requested in the 2013 rate case. PSO's estimated outside legal fees for this case more than doubled compared to the last rate case, increasing from $200,000 to $500,000. As shown in Exhibit MG-2.7, PSO's actual costs for its 2013 rate case were far less than the estimated costs for which the Company sought recovery.

PSO' [*sic*] cost estimates are significantly overstated. In my opinion, rate case expense [*sic*] should be closely monitored, and ratepayers should not be burdened with inflated legal fees and expert witness fees. I recommend that the Company's annual recovery of rate case expense be reduced from $1,018,000 to $567,500. This is a more reasonable expense level based on current market rates, and is also closer to the actual expenses incurred in the Company's 2013 rate case. I also recommend that rate case costs be recovered over a 3-year rather than a 2-year period. The longer recovery period protects against the risk of over-recovery by the utility if the Company does not file its next rate case in two years. The adjustment reduces pro forma Rate Case Expense by $319,833 and is set forth in Exhibit MG-2.7 of my Testimony.

12. **<u>Depreciation Expense.</u>** PSO proposes to increase its revenue requirement by $42,611,538 to reflect the Company's new proposed higher depreciation rates. OIEC's recommendations regarding depreciation rates are set forth in the Responsive Testimony of Mr. Jacob Pous. Mr. Pous' recommended depreciation rates, when applied to July 31, 2015, plant balances, result in a reduction of $22,482,509 to PSO's proposed increase as shown at Exhibit MG-2.10 of my Testimony. It is important to note that Mr. Pous did not address Distribution Plant depreciation rates. The Commission should look to Staff's depreciation testimony for adjustments to distribution rates.

13. **<u>Recovery of the Northeastern Unit 4 Plant Costs.</u>** PSO is proposing to retire the 460MW Northeastern Unit 4 coal plant in the middle of its useful life, but plans to continue to include both a "return on" and a "return of" the plant costs in rates. In fact, the Company even plans to accelerate the "recovery of" the plant costs over a 10-year period rather than the 25-year period now in place. Thus, there are actually three cost recovery issues associated with this plant closure:

1. PSO's plan to continue to include the un-depreciated balance of this plant in rate base, enabling the Company to continue to earn a full profit "return <u>on</u>" the abandoned plant for its shareholders;

2. PSO's plan to continue to depreciate the balance of this plant into rates so that shareholders will receive a full "return <u>of</u>" the abandoned plant costs; and

3. PSO's plan to shorten the depreciation recovery term to a 10-year period.

PSO's plan would place significant costs on ratepayers. The net un-depreciated plant balance for Northeastern Units 4 at July 31, 2015, was $79.2 million. The annual rate base "return on" this amount would be approximately $7.4 million. A 10-year accelerated depreciation of the Unit 3 and Unit 4 assets results in additional annual depreciation expense of about $13 million. This means ratepayers will unnecessarily pay higher rates of $20.4 million per year associated with the Northeastern plant closure.

PSO should not be allowed to include the costs of the retired Northeastern Unit 4 in rates. Oklahoma law is very clear on this point: only assets "used and useful" for providing utility service may be included in rate base. As explained by the Oklahoma Supreme Court in Southwestern Public Service Co., 1981 OK 136, ¶ 14, 637 P.2d at 98:

> A test year is a mirror view of the past suspended within a limited but definite time frame through which we prophesy its duplication in the future. To alter the image is to risk the distortion for the future. <u>Only the cost of those capital assets which are in actual use</u> during the test year, or whose use is so imminent and certain that they may be said, at least by analogy, to have the quality of working capital <u>may be added to the rate base</u> established by the test year in any event; and then only if appropriate counter-balancing safe guards are applied. (Emphasis added).

The used and useful standard as applied in Oklahoma precludes the treatment PSO requests. After Northeastern Unit 4 is closed, the plant will no longer be providing service to customers, and thus will no longer be used and useful, and therefore cannot be included in rates under a used and useful determination.

In Oklahoma, a utility is allowed to earn a reasonable return on utility assets at the time the assets are being used for the public. Although Unit 4 is in service during the test year, it will be taken out of service in April 2016 to coincide with the in-service dates of the $221 million of new plant investments at Northeastern 3 and other gas plants to meet PSO's proposed ECP.

PSO is seeking recovery of its ECP investment either through extending the rate base in this case out to April 2016 or through rider treatment starting in April 2016. Under either approach, the stranded Northeastern Unit 4 costs should be deducted from the rate base that includes these new ECP assets that replace Unit 4 under any scenario, whether (1) the rate base in this case is extended to April 2016, (2) a rider is established in April 2016, or (3) the assets are included in the rate base of a subsequent rate case the Company files after the assets go into service, in the event both of the scenarios (1) and (2) proposed by PSO are rejected by the Commission.

The point is, when the new ECP assets go into service, Unit 4 will be taken out of service. At that point, Unit 4 should be taken out of rate base and a return on the remaining balance should no longer be included in rates. More precisely, when the new ECP assets are included in rates. Unit 4 should be taken out of rates. or at least the return on the investment in Unit 4 should be taken out of rates.

In a recent example. specifically on point, in AEP's home state of Ohio earlier this year. the Ohio Commission denied AEP-Ohio Power's request for recovery of costs associated with the retirement of its Sporn 5 unit. Sporn 5 was a 450MW coal plant that was built and place [*sic*] in service around 1960. AEP sought to close the coal unit as part of an agreement between AEP and the Department of Justice. and asked that the Ohio Commission approve recovery of the remaining costs of the plant. with return, over an accelerated recovery period, similar to the treatment PSO seeks here. The Ohio Commission denied any recovery of the remaining costs of the closed unit. finding that the plant did not meet the "used and useful" requirements in Ohio.

Another example is a contemporaneous Regional Haze case in New Mexico. Public Service Company of New Mexico ("PNM") has agreed to write-off 50% of the stranded costs associated with two coal units retired as part of its environmental compliance plan for Regional Haze. PNM is a vertically integrated public utility subject to the jurisdiction of the New Mexico Commission. One of PNM's coal facilities, the San Juan Generating Station, consists of four coal-fired units with 1,683 net megawatts of electric generation capacity. PNM's Revised SIP sought approval to (a) abandon two coal plants at San Juan Units 2 and 3 and (b) issue Certificates of Public Convenience and Necessity for replacement power resources. As part of the settlement in that case. PNM has agreed to write-off 50% of the stranded book value of the plant assets, plus about $20M in other associated costs.

In this case. I do not view PSO's Unit 4 retirement as creating "stranded costs." Costs are not "stranded" when a utility voluntarily chooses to retire an asset in the middle of its useful life. as AEP/PSO has done here. I know of no order. case law or statute where costs have been defined as stranded costs when they result from a utility's voluntary action. To the contrary. costs have been defined as stranded when they were caused by laws or orders that mandate a major change. Here, there is no mandate that the utility close the Northeastern plant. Neither the SIP nor the FIP require such action. In fact. the FIP provides that the Northeastern units be retrofitted and continue operating.

In some cases. a plant may become uneconomic. such that it costs ratepayers more to keep the assets in service than to replace them. In such cases. the costs of stranded assets might be shared with ratepayers. Here. that is certainly not the case. According to Mr. Norwood. the Company's own analysis shows that the nominal cost of the Retrofit Both Units option (keeping the assets in service) is approximately $2 billion lower than the cost of the EPA Settlement plan (taking the assets out of service). I know of no ratemaking theory that would require ratepayers to share the costs of retired assets, when such retirement results in higher, not lower. rates.

According to the Company's own analysis and to Mr. Norwood's testimony, the [*sic*] PSO's settlement plan with the EPA is not the least-cost option for ratepayers. Instead, it appears to be a business decision of the Company that inures to the overall benefit of AEP. As such. AEP, not the Oklahoma ratepayers, should bear the additional costs of closing coal units in the prime of their useful life.

PSO states it does not track the book balances of Unit 3 and Unit 4 separately, but estimates the net book value of Unit 3 at June 30, 2015, to be $157,274,384 and the net book value of Unit 4 to be $79,164,779.

I recommend that the return on Unit 4 be suspended when the assets are no longer used and useful for providing service. The return on the Unit 4 balance should end when the return on the new ECP assets begins, [*sic*] whether the return on the new ECP assets begins through (1) extending the rate base in this case out to April 2016, (2) implementing a rider to begin in April 2016, or (3) filing a subsequent rate case after the assets go into service. Under each scenario, the rate base used to calculate the revenue requirement for the new ECP assets should be reduced by the remaining balance of the Unit 4 assets.

This treatment would eliminate the return on the assets no longer used and useful for utility service but would allow the continued return of those assets through depreciation recoveries. The impact of this adjustment is $7,429,535, as shown at Exhibit MG 2.8 of my Testimony.

14. Recommendations of Other OIEC Witnesses. The impact of the recommendations of the other OIEC witnesses is set forth in the table below, and also in Exhibit MG-2 of my Testimony.

OTHER OIEC WITNESS RECOMMENDATION IMPACTS		
1	Dave Parcell – Cost of Capital Impact	$ (27,530,533)
2	Jack Pous – Depreciation Expense Impact	$ (22,482,509)
3	Scott Norwood – Northeastern Unit 4 O&M Impact	$ (6,200,000)

15. Conclusion. My recommendations do not address every potential issue affecting PSO's revenue requirement. I addressed many of what I considered to be the material issues in this case. The fact that I did not express an opinion on a particular issue is not to be interpreted as agreement with the Company's position on my part. I reserve the right to update and amend my revenue requirement recommendations based on the responsive testimony filed by other parties and the rebuttal testimony filed by PSO. My recommendations in the rate design phase may also affect my overall revenue requirement recommendations. I will file final OIEC revenue requirement exhibits with my surrebuttal issues filing.

David C. Parcell

My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 580, 9030 Stony Point Parkway, Richmond, Virginia 23235.

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. In connection with this, I have previously filed cost of capital testimony in over 525 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") to evaluate the cost of capital aspects of the current filing of Public Service Company of Oklahoma ("PSO"). I have performed independent studies and am making recommendations on the current cost of capital 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 cost of capital recommendations for PSO are shown on Schedule 1 and can be summarized as follows:

	Percent	Cost	Return
Long-Term Debt	55.56%	4.92%	2.73%
Common Equity	44.44%	9.125%	4.06%
Total	100.00%		6.79%

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 not used the hypothetical capital structure of PSO, as proposed in the Company's filing, in my analyses. Instead, I have used the pro-forma test period capital structure of PSO.

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 pro-forma test period cost rate for long-term debt (4.92 percent) of PSO.

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 Robert B. Hevert. These three methodologies and my findings are:

Methodology	Mid-Point
Discounted Cash Flow (DCF)	8.75%
Capital Asset Pricing Model (CAPM)	6.75%
Comparable Earnings (CE)	9.50%

My recommendation for PSO focuses on the results of the DCF and CE analyses. I have focused on the 8.75 percent to 9.50 percent results for the DCF and CE analyses.

Combining these three steps into weighted cost of capital results in an overall rate of return of 6.79 percent (which incorporates a ROE of 9.125 percent).

Scott Norwood

My name is Scott Norwood. My business address is P.O. Box 30197, Austin, Texas 78755.

I am a consultant specializing in the areas of energy planning, procurement and regulation, and President of Norwood Energy Consulting, L.L.C.

I am an electrical engineer with over 30 years of experience in the electric utility industry. After graduating from the University of Texas in 1980, I began my career as a power plant engineer for the City of Austin's Electric Utility Department. In January 1984, I joined the staff of the Public Utility Commission of Texas ("PUC" or "Commission") where I served as Manager of Power Plant Engineering and was responsible for addressing resource planning, fuel and purchased power cost issues which came before the Commission. In 1986, I joined GDS Associates, a Marietta, Georgia based consulting engineering firm. I was elected a Principal of GDS in 1990, and directed the firm's Deregulation Services Department until January 2004, when I left to form Norwood Energy Consulting, LLC. The focus of my current consulting practice is electric utility regulatory consulting. My resume is attached as Exhibit SN-1.

I am testifying on behalf of Oklahoma Industrial Energy Consumers ("OIEC").

I have testified in numerous past base rate and fuel proceedings before the Oklahoma Corporation Commission ("OCC" or "Commission"), including a number of past cases involving Public Service Company of Oklahoma ("PSO").[10] I filed testimony addressing PSO's request for approval of a proposed environmental compliance plan in OCC Cause No. PUD 201200054. I have also participated on behalf of OIEC in past Commission proceedings involving environmental compliance issues, including OCC Cause No. PUD 201100077, and in public hearings involving the 2012, 2013 update, and 2015 Integrated Resource Plans ("IRP") filed by PSO and Oklahoma Gas and Electric Company ("OG&E"). Through my participation in these past projects, I have become very familiar with the planning and operations of power supply resources on PSO's system. I am also familiar with the environmental compliance activities of AEP's operating companies in Arkansas, Texas and Virginia as a result of my review of regulatory filings in those jurisdictions. In addition, I have submitted testimony on utility regulatory matters in past proceedings before the Federal Energy Regulatory Commission ("FERC"), and before state regulatory commissions in Arkansas, Georgia, Iowa, Illinois, Louisiana, Michigan, Missouri, New Jersey, Texas, Virginia, Washington, and Wisconsin. My Exhibit SN-1 provides a list of my past testimony in Oklahoma and other jurisdictions over the last ten years.

The purpose of my testimony is to present my findings and recommendations regarding PSO's request for cost recovery for the Company's environmental compliance plan ("ECP") under its settlement agreement with the United States Environmental Protection Agency

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[10] For example, see testimony of Scott Norwood on behalf of OIEC in OCC Cause Nos. PUD 2002 00754, PUD 2006 00030, PUD 2006 00285, PUD 2007 00365, PUD 2008 00144, PUD 2009 00158, PUD 2010 00050, PUD 2010 00092, PUD 2010 00172, PUD 2011 00106, PUD 2011 00129, PUD 2012 00054 and PUD 2013 00188.

("EPA"), the State of Oklahoma and the Sierra Club (hereinafter referred to as the "EPA Settlement" or "Settlement"), which was executed by the parties in October of 2012. My testimony also addresses PSO's proposed adjustment to production O&M expenses to reflect the scheduled retirement of Northeastern Unit 4 in April 2016.

OIEC is an association which represents the interests of certain industrial and other large energy consumers. OIEC's members are among the largest users of electricity on PSO's system, and therefore are very sensitive to any electric rate increases proposed by PSO. Industries served by PSO often operate in highly competitive business environments and therefore are interested in ensuring that the Commission determine [*sic*] rates for PSO that are reasonable and that reflect the lowest reasonable cost resources necessary to deliver reliable electric service.

My primary findings and recommendations are as follows:

PSO Request for Recovery of <u>EPA Settlement Costs</u>

- It is my understanding that PSO's recovery of costs of the EPA Settlement is subject to a determination that the costs are reasonably incurred and that the Settlement adheres to the lowest reasonable cost standard. According to PSO's own analyses immediately before entering into the EPA Settlement, the Settlement is forecasted to be much more costly and risky than the alternative of retrofitting and continuing to operate both Northeastern Coal units (hereinafter referred to as the "Coal Retrofit" option) over a wide range of scenarios evaluated by PSO. As summarized in Table 1, under PSO's August 2012 base case analysis, the nominal cost of the EPA Settlement is approximately $1.9 billion higher ($278 million higher on a present value basis) than the Coal Retrofit alternative.

Table 1

PSO's August 2012 Environmental Compliance Analysis
Coal Retrofit Cost (Savings) vs EPA Settlement
($Millions)

	2011-2040 Cum NPV	2011-2040 Nominal Cost
Late-2011 Analysis		
Base Fuel 25 Yr Coal	($482)	($2,027)
Avg All 5 Scenarios	($273)	($1,185)
August 2012 Update		
Base Fuel 25 Yr Coal	($278)	($1,860)
Avg All 7 Scenarios	($97)	($995)
High Fuel Prices	($601)	($3,580)

Sources are PSO witness Weaver's Substituted Exhibits SCW-7 and SCW-8, PSO's witness Fate's Exhibit SLF-2, and PSO's response to AG 1-4 from OCC Cause No. PUD 201200054.

- PSO's economic analysis of the EPA Settlement was unreasonably biased in favor of the Settlement, making the Company's decision to enter into the Settlement even more unreasonable. The major biases favoring the Settlement were: 1) including more than $3.7

billion in highly speculative carbon taxes; 2) assuming in the base case that the Northeastern units were capable of operating only 50 years, despite evidence that a 60 year operating life was more likely; and 3) assuming that the 470 MW of capacity lost due to the mandated retirement of Northeastern Unit 4 in 2016 would not have to be replaced until 2024. If PSO's analysis of the EPA Settlement had been properly adjusted to exclude such unreasonable biases, the advantage of the Coal Retrofit alternative over the EPA Settlement would have been much higher than suggested by the results in Table 1.

- PSO's decision to enter into the proposed EPA Settlement, which was executed in October of 2012, was also premature because, at that time, EPA's MATS rule and RH Federal Implementation Plan ("FIP") for Oklahoma remained under legal appeal, and the EPA's carbon emissions regulations had not even been proposed.

- PSO has not re-evaluated the EPA Settlement in light of EPA's final Clean Power Plan ("CPP") regulations governing carbon emissions from existing generating facilities. These regulations indicate that the level of carbon compliance costs assumed by PSO in its economic analyses of the EPA Settlement was greatly overstated. This means that the Company's forecasts of the cost advantage of the Coal Retrofit compliance option presented in Table 1 above were significantly understated and that the level of coal plant retirements agreed to by PSO under the EPA Settlement were [*sic*] not necessary for compliance with the established carbon emissions standards.

- The EPA Settlement will virtually eliminate fuel diversity on PSO's system by mandating the permanent early retirement of Northeastern coal units 3 and 4, which represent over 90% of the Company's existing coal-fired generating capacity. As a result of these retirements, coal-fired generation will decline from the current level of approximately 35% of PSO's total energy supply to approximately 3% of total energy supply. This loss of fuel diversity is expected to result in significantly higher and more volatile fuel prices for PSO's customers in the future.

- PSO has not evaluated the long-term customer rate impacts of the EPA Settlement. Based on the cost information provided by PSO, the Settlement is expected to disproportionately impact high load-factor customers, since virtually all of the forecasted cost increase resulting from the Settlement occurs in fuel costs.

Based on the above findings and other findings discussed in my testimony, I have concluded that PSO's decision to enter into the EPA Settlement in October 2012 was unreasonable and is likely to disproportionately impact high load factor customers. Accordingly, I recommend that the Commission:

- Disallow replacement capacity costs arising from purchased power contracts entered into by PSO with Calpine, Exelon and Tenaska to replace capacity that will be lost as a result of the required retirement of the Northeastern Unit 4 in 2016 under the EPA Settlement; and

- Authorize cost allocation methods to ensure that high load factor customers are not required to pay a disproportionate share of the increased fuel costs arising from the mandated early retirement of PSO's coal units under the EPA Settlement. OIEC will present proposals designed to ensure a more equitable allocation of cost increases resulting from the EPA

Settlement in its testimony addressing cost allocation and rate design issues. to be filed later in this case

<u>Northeastern Unit 4 Non-Fuel O&M</u>

• PSO proposes to adjust test year non-fuel O&M expenses by approximately $2.1 million to account for savings resulting from the planned retirement of Northeastern Unit 4 in April of 2016. This adjustment represents less than 10% of the total non-fuel O&M costs incurred for Northeastern Units 3 and 4 last year. The Company's workpapers do not demonstrate why such a small adjustment in O&M spending reasonably represents the cost savings from retirement of Northeastern Unit 3. Based on my review of the nature and level of past costs incurred for operations and maintenance of Northeastern Unit 3 and 4, I recommend that PSO's test year non-fuel O&M expenses instead be reduced by $6.2 million, which represents just under 24% of the total combined non-fuel O&M costs reported for the Northeastern coal units last year and 17% lower than the retirement O&M savings estimated by PSO in OCC Cause No. PUD 201200054.

<u>Summaries of Responsive Testimony of Public Utility Division</u>

<u>Dr. Craig R. Roach, PH.D</u>

The purpose of my Responsive Testimony is to review PSO's request for recovery of the costs incurred to implement its Environmental Compliance Plan ("ECP").

The major actions relate to compliance with the Regional Haze Rule ("RHR") and the Mercury and Air Toxics Standard ("MATS") at PSO's two large coal-fired Northeastern units. PSO's implementation of the EPA Settlement with respect to these two Northeastern units called for (a) emissions consistent with the use of low sulfur coal starting in 2014; (b) the retirement of one of the coal units by 2016; (c) the partial replacement of the power capacity of the retired unit with the purchase of capacity from a natural gas-fired combined cycle plant by 2016; (d) the retrofit of the other coal plant with Dry-Sorbent Injection ("DSI"), Activated Carbon Injection ("ACI"), and Fabric Filter Baghouse ("FF") [*sic*] by 2016; (e) limited capacity factors for the operating coal unit from 2021 to 2026; and (f) the retirement of the second coal unit by 2026.[11]

There are other actions aimed primarily at control of nitrogen oxide ("NOx") emissions. These include Dry Low NOx burners at the Comanche plant. Included as well are NOx controls at Northeastern Units 2, 3, and 4 and at Southwestern Unit 3; PSO terms the NOx controls for these units as Separated Over-Fire Air or "SOFA."

The standard for judging PSO's request for cost recovery is the prudence of its choice of ECP. The core of a prudence review is a comparison of alternative approaches to compliance.

I recommend that the Commission approve cost recovery through the base rate approach for PSO's environmental compliance plan, but with important conditions. Note that approval of cost recovery is warranted because PSO demonstrated the prudence of its choice of the EPA Settlement through its extensive evaluation of alternatives in Cause 54.

[11] Roach Responsive Testimony in Cause No. PUD 201200054, page 27 lines 1 to 14.

This recommendation includes rejection of the test-year waiver. Costs incurred more than six months past the end of the test year cost recovery would be accumulated in a regulatory asset for which PSO may seek recovery in a future rate case.

I have six conditions for my recommendation to approve cost recovery.

First, PSO should be held to a hard cap for its DSI/ACI/FF investment at Northeastern 3. I recommend that the hard cap be set at $210 million, which is the cost estimate PSO used for the investment in evaluating the ECP against other alternatives in Cause 54. Specifically, under the hard cap, PSO may not seek recovery of more than $210 million adjusted appropriately for allowance for funds used during construction ("AFUDC") and overhead, regardless of the timing of cost recovery.

Second, PSO should not be allowed to recover any costs for its Comanche Dry Low NOx burners until the investments are in service. This condition also includes rejection of the test-year waiver.

Third, the Commission should deny cost recovery for the accelerated depreciation that PSO seeks to recover for Northeastern Units 3 and 4 over the 2016 to 2026 period. To mitigate rate increases, depreciation for the undepreciated, "original" costs of these two units should continue on its current pace to 2040.

Fourth, PSO should be required to seek approval in this proceeding through rebuttal testimony for PSO's SOFA investments on Northeastern Units 3 and 4, Southwestern Unit 3, and the majority of its investment in Northeastern Unit 2. While PSO claims to have received approval for these expenditures, and PSO has already included these investments in rate base, I have not seen evidence that the Commission has granted explicit approval for these investments. I have no reason at this time to argue against cost recovery for these investments, but the Commission must be given the opportunity for an explicit approval.

Fifth, PSO should be required to seek approval in this proceeding through rebuttal testimony for all three power purchase agreements related to replacing the power from the retired Northeastern Unit 4. I have previously supported and support here cost recovery for the Calpine power purchase agreement ("PPA"). I have no reason at this time to argue against cost recovery for the other two PPAs, but the Commission must be given the opportunity for an explicit approval of all three PPAs.

Sixth, the Commission should not rule on the prudence of the planned retirement of the retrofitted Northeastern 3 unit in 2026 until a Commission hearing is held in or about 2020. The same would go for a ruling on the capacity factor limitations for that unit. This condition is given added support by the fact that PSO itself is unsure what it will do with Northeastern 3 in 2026 – as evidenced by its extensive analysis in this proceeding of converting the unit to natural gas at that time and by its recent analysis of repowering the unit in PSO's Integrated Resource Plan ("IRP") update.

<u>David J. Garrett – Cost of Capital</u>

David Garret [*sic*] for the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission") filed Responsive Testimony on October 14, 2015, in Cause No. PUD 201500208. The purpose of Mr. Garrett's testimony is to review five items in the July 1. 2015. Application of the Public Service Company of Oklahoma ("PSO" or "The Company") in Cause No. PUD 201500208. The items he evaluated were:

- the Company's earned return on equity ("ROE")
- the Company's capital structure
- the Company's embedded cost of long term debt
- the Company's requested rate of return ("ROR")
- the Company's Long Term—Short Term Incentives

PSO's cost of capital is comprised of two components: debt and equity. While the cost of debt is determined by fixed, contractual interest payments, the cost of equity must be estimated through financial models. Mr. Garrett employed three widely-used financial models on a group of similar "proxy" companies to arrive at a fair, reasonable and accurate estimate of the Company's cost of equity in this case, including: 1) the Discounted Cash Flow Model; 2) the Capital Asset Pricing Model; and 3) the Comparable Earnings Model. Finally, Mr. Garrett conducted an objective 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 it generates. The general DCF Model may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF model, which is what Mr. Garrett used in his analysis. All else held constant, the Quarterly Approximation DCF Model results in the highest cost of equity estimate for the utility in comparison to other DCF models. The average DCF result of the proxy companies using the Quarterly Approximation DCF model is 7.96 percent.

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk. There are essentially three terms within the CAPM equation that are required to calculate the required return (K): 1) the risk-free rate (RF); 2) the beta coefficient (β); and 3) the market risk premium (RM – RF), which is the required return on the overall market less the risk-free rate. Mr. Garrett calculated the betas for each proxy company using linear regression. The equity risk premium ("ERP") is the required return on the market portfolio less the risk-free rate. The ERP is one of the most [*sic*] factors in estimating cost of capital. There are three well-known, reasonable, and widely-recognized ways to estimate the ERP: 1) calculating a historical average; 2) taking a survey of experts; and 3) calculating the implied equity risk premium. Mr. Garrett incorporated each one of these methods in determining the ERP used in his CAPM analysis. The average CAPM result for the proxy group was 6.54 percent.

The Comparable Earnings Model ("CEM") involves simply averaging the earned returns on equity of other utility companies. In utility rate cases, analysts often perform the CEM on the same proxy group of regulated utilities used in the CAPM and DCF analyses. Technically, however, this analysis should be on a group of unregulated, competitive firms with similar risk profiles, but such a group of competitive firms does not exist because utilities have such little risk. However, in conducting his CEM analysis, Mr. Garrett averaged the annual earned returns on equity for each of the proxy companies from 2005–2014. The composite average and final result of the CEM is 9.17 percent.[12]

Capital structure refers to the way a firm finances its overall operations through external debt and equity capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. Because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation. Using technical analysis rather than simply looking at the capital structures of the proxy group, Mr. Garrett estimated the optimal capital structure for PSO, which consists of about 65 percent debt and 35 percent equity. Nonetheless, PUD is recommending a debt ratio of only 56 percent which was the debt ratio present during the test year. Imputing the optimal capital structure in this case would result in an abrupt adjustment, rather than a gradual one. Additionally, Mr. Garrett recommended PSO's proposed cost of debt of 4.92 percent.

Mr. Hevert uses two forms of the DCF Model in his analysis, including the Constant Growth DCF Model and the Multi-Stage DCF Model. Mr. Garrett believes the results of Mr. Hevert's Constant Growth DCF Model are unreasonably high due to his high growth rate estimates. Mr. Hevert's growth estimates in prior cases have been subject to extreme volatility. In addition to employing a constant growth DCF Model, Mr. Hevert also employed a Multi-Stage DCF Model. Multi-Stage DCF Models are generally used for firms with high growth opportunities. Regardless, Mr. Garrett argues the results of Mr. Hevert's Multi-Stage DCF Model are unreasonably high.

Mr. Garrett argues that Mr. Hevert's estimate of 10.5 percent for the equity risk premium ("ERP") is inappropriate. While Mr. Garrett conducted a thorough, robust analysis of the ERP using three reasonable, widely-accepted methods, Mr. Hevert used none of these methods. Mr. Garrett recommends that the Commission disregard Mr. Hevert's CAPM results due to his inappropriately high estimate for the ERP. Also, Mr. Garrett argues that Mr. Hevert's Bond Yield Plus Risk Premium Analysis is inappropriate for several reasons. Thus, Mr. Garrett recommends the Commission disregard Mr. Hevert's Bond Yield Plus Risk Premium analysis.

In addition to having low levels of market risk, PSO also has low levels of firm-specific business risk. Investors do not expect a return for assuming firm-specific risk because such risk can be eliminated through diversification. Only market risk is rewarded by the market. Therefore, Mr. Garrett does not support any discussion of the Company's firm-specific business risks in the cause because it should have no meaningful effect on the cost of equity estimate even if it [*sic*] relevant to other issues in the rate case.

Mr. Garrett recommended the Commission not allow flotation costs as argued by Mr. Hevert. Flotation costs generally refer to the underwriter's compensation for the services it provides in connection with the securities offering. Mr. Hevert argues the Company should receive a flotation cost adjustment through the DCF Model. Mr. Garrett believes the Commission should not allow recovery of flotation costs in this case for the following three

[12] Exhibit DG-C-17.

reasons: 1) flotation costs are not actual "out-of-pocket" costs; 2) the market already accounts for flotation costs; and 3) it is inappropriate to add any additional basis points to a cost of equity proposal that is already far above the true required return.

PSO's pro forma expense levels include $8,739,895 of annual, or short-term, incentive compensation and $3,782,540 of long-term incentive compensation. The Commission should disallow 50 percent of short-term incentive compensation and 100 percent of long term incentive compensation as it has done in the past.

Mr. Garrett requested the Commission adopt the following recommendations: 1) a cost of equity of 9.25 percent, which is the highest point in a range of reasonableness of 8.75 to 9.25 percent; 2) a cost of debt of 4.92 percent, as proposed by the Company; 3) a capital structure consisting of 56 percent debt and 44 percent equity; 4) an overall weighted average cost of capital of 6.83 percent, which is the highest point in a range of reasonableness of 6.61 to 6.83 percent; and 5) an adjustment of $8,152,488 to reduce pro forma incentive compensation expense. These recommendations are fair, just, and reasonable to both ratepayers and the Company.

<u>David J. Garrett – Rate of Depreciation</u>

David Garrett of the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission") filed Responsive Testimony on October 14, 2015, in Cause No. PUD 201500208. The purpose of Mr. Garret's [*sic*] testimony is to review the rate of depreciation in the July 1, 2015, Application of the Public Service Company of Oklahoma ("PSO" or "The Company") in Cause No. PUD 201500208.

"Depreciation systems" are designed to analyze grouped property in a systematic and rational manner. A depreciation system may be defined by four primary parameters: 1) a method of allocation; 2) a procedure for applying the method of allocation; 3) a technique of applying the depreciation rate; and 4) a model for analyzing the characteristics of vintage property groups. In this case, Mr. Garrett used the straight-line method, the average life procedure, the remaining life technique, and the broad group model.

The most common actuarial method used by depreciation analysts is called the "retirement rate method." In the retirement rate method, original property data, including additions, retirements, transfers, and other transactions, are organized by vintage and transaction year. The retirement rate method is ultimately used to develop an "observed life table", which shows the percent of property surviving at each age interval. This pattern of property retirement is described as a "survivor curve." The most widely used survivor curves for this curve fitting process are commonly known as the "Iowa curves." To calculate the average remaining life for each account, Mr. Garrett obtained the Company's aged property data by installation and transaction year, including additions, retirements, gross salvage and removal cost data. Mr. Garrett used this data to develop an observed life table for each account and then fitted the observed retirement pattern with a smooth, complete Iowa curve using both mathematical and visual curve fitting techniques. Mr. Garrett obtained the average remaining lives for each account based on the Iowa curves he selected. The specific process for conducting service life and salvage analysis in order to develop depreciation rates depends on whether the group of property being analyzed is "life span" property or "mass" property.

Life span property groups often contain a small number of large units, such as a generating unit. Life span property is retired concurrently. In determining the overall depreciation rate of life span property, it is important to estimate the amount of interim and terminal retirements. Mr. Garrett determined the interim amounts retired for each life span account by estimating the percent of original cost that will be retired during the life span of each unit. Mr. Garrett determined the percent of property surviving based on the interim Iowa curves he selected for each account. Once Mr. Garrett estimated the interim retired amounts for each life span account, he subtracted this amount from the total amount of projected retirements in order to calculate the estimated amount of terminal retirements. To estimate net salvage for each life span unit, Mr. Garrett calculated the weighted net salvage percents from both terminal and interim retirements. Through statistical analysis of historical interim net salvage, Mr. Garrett determined that the Company's proposed interim net salvage percentages were reasonable. To calculate the terminal net salvage percentages, Mr. Garrett divided the estimated demolition cost for each unit (less the contingency factor) by the estimated amount of terminal retirements.

Mass property includes depreciable property that is not a part of life span property. Mass property accounts usually contain a large number of small units that will not be retired concurrently. The two key factors that Mr. Garrett had to estimate were remaining life and net salvage. To estimate remaining life, Mr. Garrett performed actuarial analysis on the Company's aged plant data to obtain observed survivor curves. To estimate net salvage for each mass account, Mr. Garrett considered historical net salvage percentages. Mr. Garrett concluded that the Company's proposed net salvage percentages for each mass property account were reasonable.

Calculated Accumulated Depreciation ("CAD") is the calculated balance that would be in the accumulated depreciation account at a point in time using current depreciation parameters, such as average service life and net salvage. There is almost always an imbalance between the actual accumulated depreciation amount and the CAD. If the remaining life application technique is used, as Mr. Garrett did in this case, any imbalance between the actual accumulated depreciation amount and the CAD is "automatically" amortized over the remaining life of the account and no additional adjustment is required.

The differences in PSO's and PUD's proposed rates arise primarily from several key issues: 1) Premature Retirement of Northeast Units 3 and 4; 2) Service Life Estimates for Mass Accounts; and 3) Terminal Net Salvage Estimates for Life Span Accounts.

In the interest of fairness to ratepayers, the probable retirement date for Northeast Units 3 & 4 should remain at 2040 for analytical purposes. PSO is planning on retiring Northeast Units 3 and 4 in 2026 and 2016, respectively, and the Depreciation Study reflects the recovery of Northeast Units 3 and 4 utilizing the retirement date of 2026. However, the original probable retirement date for Northeast Units 3 and 4 is 2040, which represents the units' actual, economic useful life. Thus, PSO is prematurely retiring these units about 14 years before the end of their useful lives, which increases the rate impact to customers by about $12 million. In the interest of fairness to ratepayers, the Company should not be allowed to accelerate the recovery of its capital investments in Northeast Units 3 & 4.

The net effect of PUD's adjustment to mass property accounts is a decrease of about $11 million to the annual accrual. Mr. Garrett relied on both mathematical and visual curve fitting in order to determine the best fitting Iowa curve for each account. Many of the Iowa curves Mr. Garrett selected were the mathematically best fitting curve. For some accounts, however, the mathematically best fitting curve resulted in average lives that appeared unreasonably long. For those accounts, Mr. Garrett chose the mathematically highest ranked Iowa curve and average life that appeared reasonable.

Mr. Garrett made adjustments to PSO's proposed terminal net salvage percentages. Mr. Garrett calculated the terminal net salvage percentages by dividing demolition cost [*sic*] for each location by the amount of terminal retirements for each location. The difference [*sic*] in PSO's and PUD's terminal net salvage rates arise primarily from two factors related to the estimated decommissioning costs: 1) removal of the escalation factor; and 2) removal of the contingency factor. PSO applied a 2.5 percent escalation factor to the estimated demolition costs, which adds about $77 million to the total costs. The Commission should not consider escalated demolition costs in this case for the following reasons: 1) the escalated costs do not appear to be calculated properly; 2) the Company did not offer any testimony in support of the escalation factor; 3) an escalation factor that does not consider any improvements in technology or economic efficiencies likely overstates future costs; 4) it is inappropriate to apply an escalation factor to demolition costs that are likely overestimated; 5) asking ratepayers to pay for future costs that may not occur falls outside of the "known and measurable" standard; and 6) the Commission has not approved escalated demolition costs in previous cases. In its demolition cost study, S&L applied a 15 percent contingency factor to its cost estimates, and a negative 15 percent contingency factor to its scrap metal value estimates. The Company provides little justification for this contingency factor other than the plants might experience uncertainties and unplanned occurrences. This reasoning fails to consider the fact that certain occurrences could reduce estimated costs. Furthermore, it is very likely that S&L has overestimated the demolition cost. It would be especially inappropriate to consider an arbitrary and unsupported contingency factor that increases costs that are already overestimated.

Mr. Garrett recommends an adjustment of $25,435,929 to reduce the Company's proposed depreciation expense. PUD's adjustment is fair and reasonable to the Company and to ratepayers.

<u>Kiran Patel</u>

Kiran Patel is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Ms. Patel filed Responsive Testimony on October 14, 2015. The purpose of her testimony was to provide detail of the areas that were reviewed by PUD and to discuss the review process. In addition, her testimony is to support her areas of review relative to the PSO application for an order adjusting its rates, changes [*sic*], and terms and conditions of service in the State of Oklahoma.

PUD analysts who have filed testimony on the [*sic*] behalf of PUD and the areas covered are as follows:

- Robert Thompson will cover the PUD accounting exhibit and overall accounting adjustments
- David Garrett will cover the Depreciation and Cost of Capital
- Jeremy Schwartz will cover Rate Design and Cost of Service
- Kathy Champion will cover General Discussion on Riders
- Jason Chaplin will cover SPP Transmission Cost and related matters
- Geoffrey Rush will cover Payroll Expenses and Director's Salary and Expenses
- Hunter Hogan will cover Rate Base and related expenses
- Craig Roach will cover PSO's Environmental Compliance Plan
- Kiran Patel will cover Rate Base and related expenses

PUD reviewed all information and testimony provided by the Company as a part [*sic*] the Application in this cause. PUD further reviewed Commission orders, testimony related to areas in prior causes, and work papers relating to PSO. PUD communicated with the Company through email, phone calls, in-person reviews, electronic information/data requests and reviewed responses to these requests.

In response to the application filed by PSO, for the assigned areas, Ms. Patel reviewed the following areas: Annual Report, Regulatory Financial Report, SEC 1 OK Report, Taxes other than Income, Bad Debt Expenses, Overhead and Maintenance, FERC Account 500s, O&M Generation Non-Fuel, Fuels and/or Purchased Power, Informational /Instructional/Miscellaneous/Sales expense and Rate Case Expense.

After conducting a thorough review of PSO's Application package and conducting an on-site visit, Ms. Patel proposes adjustments as shown below:

For Current Rate Case expense, PSO estimated current rate case expense in a WP H-13 at $509,000. PSO proposed an amortization over 24 months; PUD agreed with PSO [*sic*] recommendation for amortized [*sic*] over two years. Based on prior rate case orders prescribing amortization of rate case expenses over a 24-month period [*sic*].

For Prior Rate Case Expenses, PSO recommends an annualized adjustment (WP H-13), in the amount of $555,601. PSO proposed an amortization over 24 months; PUD agreed with PSO [*sic*] recommendation for amortized [*sic*] over two years.

For AEPSC adjustments billed to Rate Case Expense, PUD proposed adjustment H-8 to decrease AEPSC overhead incentive expenses in the amount of ($131,493) that added in rate case expenses.

For the Rate case expenses, PUD proposed an adjustment H-8, (decrease) in the amount of $131,493 AEPSC Billing included. PUD adjusted Incentive Compensation, Restricted Stock Incentives, and Stock-based Compensation that totaled of $131,493 in WP H-13.1 line [*sic*] 14, 15 and16. PSO's adjusted rate case expense in the test year amount of $1,602,588 in the rate base and PUD proposed an annualized amount of $1,471,095 in the rate base [*sic*].

For the Expert Witness Rate Case expense; PUD proposed adjustment No. H-11, to increase $500,000 for the expert witness rate case expense. PUD then recommends that this portion of the rate case expense amount be amortized over a two year period and true it [*sic*] up all cost [*sic*] when incurred.

For the Taxes other than Income Taxes, PSO's adjustment was a decrease in [*sic*] Federal Insurance Contribution Act tax of $83,433 and a decrease of $190,749 for Franchise and Excise Tax. Payroll tax is covered by PUD witness Geoffrey Rush. PUD has reviewed the Company's prepared binder and all supporting documents. The franchise tax is a minimum of $10.00 and a maximum of $20,000. PUD does not propose any adjustment.

For the Bad Debt expenses, PSO's bad debt is factored, meaning PSO sells a portion of bad debt to a third party at a discount. PSO still performs collection services for the accounts receivable amount and also maintains a reserve for the uncollectable amounts. PSO proposed a ($221,598) decrease for the factoring. PUD witness Robert Thompson will address this in his testimony. PUD agrees with the Bad Debt expense and does not make any adjustments to the Bad Debt Expense account.

For Fuel and Purchase Power revenues, PSO proposed an adjustment to remove $791,339,138 of fuel-related revenue collected under the OCC-approved Fuel Adjustment Clause ("FAC") from the rate base revenue requirement. There are four (4) adjustments, including for [*sic*] WP H-2-22 Purchased Power revenue adjustment ($37,354,310), WP H-2-23 revenue adjustment ($750,301,127) and WP H-2-25 Miscellaneous revenue adjustment ($3,683,701). All fuel-related revenue has been moved into the FAC.

PSO also proposed four adjustments to remove $695,152,152 of fuel expenses recovered under the FAC from the rate base. These adjustments are shown on WP H-2-22 ($264,126,597), WP H-2-22 ($431,017,336) and WP H-2-26 AEPSC Billings ($8,219). PUD agrees with the fuel-related revenue and expenses adjustment. It is consistent with Final Order No. 639314 in Cause No. PUD 201300217, which removed fuel related revenues and expenses from base rates. PUD has no objection to PSO's fuel-related revenue and expenses adjustments.

For O&M Generation Non-Fuel, PUD reviewed the testimony of PSO witness Mr. Gary Knight, had an on-site meeting with him in PSO's Oklahoma City office, and also reviewed WP H-2-42 to reconcile $79,406,082 with the general ledger. PUD has not proposed any adjustments to O&M Generation Non-Fuel. PUD agreed with the Company's approach and adjustments.

For Informational/Instructional/Miscellaneous-Sales Expense, PUD proposes Adjustment No. H-10 [*sic*] amount of $183,241 concerning expenses for Edison Electric Institute ("EEI"), lobbying expense, Chamber of Commerce, Hugo Lions Club, etc., that do not appear to benefit ratepayers exclusively and, therefore, should not be recovered from ratepayers. PUD recommends that this kind of expense be shared between ratepayers and stockholders.

Hunter Hogan

Mr. Hunter Hogan is employed by the Public utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC") and filed Responsive Testimony on October 14, 2015, in Cause No. PUD 201500208. The purpose of Mr. Hogan's testimony is to present PUD's recommendation for his assigned areas in response to the application filed by the Public Service Company of Oklahoma.

Mr. Hogan recommended four adjustments to the areas of prepayments, customer deposits, off system trading deposits, and materials, [*sic*] supplies balance. For the remaining eighteen areas that Mr. Hogan reviewed, he is not recommending any adjustments. These areas include: adjustments to rate base, fuel inventories, advances for construction balances, policy on refunding customer deposits, analysis of customer deposits, tax collections payable and deferred credits balances, miscellaneous deferred debits balances, operating reserves and accrued liabilities, consolidated companies and subsidiaries balance sheet, income statements for the test year and first preceding year, cost allocation basis, affiliate/subsidiary general data, affiliate/subsidiary contracts, assets sold/transferred to affiliates/subsidiaries, services/products from affiliates/subsidiaries, services/products to affiliates/subsidiaries.

For the first adjustment, Mr. Hogan recommended PUD adjustment No. B-8, to decrease the prepayment balance by ($1,709,670). PSO used a 13-month average for prepayment amount, after reviewing data request responses and 6 month post test year numbers. Mr. Hogan testified that using the 13-month post test year average balance represents an up to date account balance. For the second adjustment, Mr. Hogan recommended PUD adjustment No. B-1 to decrease the customer deposits account by ($1,609,152). Mr. Hogan stated that utilizing the 13-month post test-year average in comparison to PSO's year-end balance allows for up to date account balances of customer deposits. For the third adjustment, Mr. Hogan recommended PUD adjustment No. B-5 to increase the off system trading deposits balance by $876,539. PSO used a 13-month average for off system trading deposits amount, after reviewing data requests and post test-year numbers. Mr. Hogan testified that using the 13-month post test-year average balance represents an up to date account balance [*sic*]. For the fourth adjustment, Mr. Hogan recommended PUD adjustment No. B-2 to decrease the materials, supplies account by ($182,869). Mr. Hogan believes that utilizing the 13-month post test-year average in comparison to PSO's year-end allows for an up to date account balance of materials, [*sic*] supplies.

Mr. Hogan did not propose any adjustments to the remaining areas. The remaining areas were not adjusted by PSO and do not have an impact on the rate base. Mr. Hogan reviewed these areas and did not find any areas of concern nor any adjustments that were required.

Geoffrey M. Rush

Geoffrey M. Rush is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC") and filed Responsive Testimony on October 14, 2015, in Cause No. PUD 201500208. The purpose of Mr. Rush's testimony is to present PUD's recommendation for his assigned areas in response to the application filed by the Public Service Company of Oklahoma.

Mr. Rush reviewed all information and testimony provided by the Company in this Cause related to his assigned areas of review. In addition, PUD reviewed previously filed testimony in related areas for prior causes, and work papers relating to PSO. Mr. Rush communicated with the Company through email, phone calls, in-person reviews, electronic information/data requests and reviewed responses to these requests and those of other parties to this cause.

Mr. Rush recommended an adjustment which will decrease Payroll Expenses in the amount of ($1,500,134.36). This adjustment recognizes six months post test year data, which captures recent information. In the area of Payroll Taxes, Mr. Rush recommended an adjustment in the amount of ($104,334.34), based on PSO's effective rate of 6.955 percent. The amounts of these adjustments represent a reduction of $1,604,468.70. PUD believes that the adjustments made are fair, just, reasonable and in the public interest.

For the remaining areas that were reviewed, there are no adjustments being recommended. These areas include: Payroll Description, General Salary Adjustments, Part-Time Employees, Payroll Distributions, Work Force Level Changes, Wage & Salary Surveys, Accrued Compensated Absences, Directors' Fees and Executive Salaries, Directors/Executive Expense Vouchers and Executive Salary Surveys.

<u>Jason Chaplin</u>

Jason Chaplin is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Mr. Chaplin filed Responsive Testimony on October 14, 2015. The purpose of his testimony was to give an explanation of the review and recommendations of PUD pertaining to PSO's request to adjust the recovery of certain SPP transmission costs through their SPP Transmission Cost ("SPPTC") Tracker and base rates.

PUD reviewed all information and testimony provided by the Company in this Cause related to PSO's request to adjust recovery of SPP transmission costs through their SPPTC and base rates. PUD further reviewed Commission orders, testimony to related areas in prior causes, and work papers relating to PSO. PUD communicated with the Company through email, phone calls, and reviewed responses to data requests.

PSO requests that they be allowed to implement accounting similar to that approved for storm recovery for the costs being recovered in base rates for certain SPP costs. PSO requests to defer, as a regulatory asset or liability, the difference in actual expenses and the amount included in PSO's base rates. For SPP transmission expenses, PSO would defer the difference between actual expenses and $46,133,269 related to SPP Schedules 1A, 9, 11 and 12 that are not included in the SPPTC tracker.

PSO is proposing five adjustments to its operating income related to PSO's base rate SPP expenses. The table below summarizes the five adjustments:

Adjustment	Amount	Schedule H-03 SP WP Reference
Annualize Oklahoma TransCo, Prairie Wind and Transource Missouri Base Plan Funding Costs Not Recovered Through PSO's SPPTC Tracker	$1,183,801	SP WP H-02-28
Annualize Oklahoma TransCo Base Plan Funding Costs Per 2015 SPP Formula Rate Filing	$1,653,610	SP WP H-02-29
Annualize SPP Network Integration Transmission Service Costs	$2,149,004	SP WP H-02-31
Annualize SPP Administrative Fee	$685,960	SP WP H-02-31
Annualize SPP FERC Assessment Fee	$37,901	SP WP H-02-31

PUD recommends that use of riders should be limited in number and scope and that a standard set of criteria be used to evaluate the approval and continuation of riders. For this case, PUD used the following criteria to review each of the riders in use or proposed by PSO and recommends the use of these criteria in evaluating future rider requests:

- Are costs substantial and recurring – relative to overall costs?
- Are costs volatile and unpredictable?
- Are the costs outside utilities control?

PUD further recommends that language be added to the tariff to require a broader review before approval and implementation of new factors, if any annual adjustment exceeds 50 percent. 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.

PUD recommends the Commission approve the following:

Not allow PSO to defer, as a regulatory asset or liability, the difference between actual expenses and the amount included in PSO's base rates

Approve PSO's five (5) adjustments to operating income related to PSO's base rate SPP expenses

Approve modification to SPPTC tariff to limit annual adjustments

PUD believes these recommendations balance the interests of parties, are fair, just and reasonable, and in the public interest.

Kathy Champion

Kathy Champion is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Ms. Champion filed Responsive Testimony on October 14, 2015. The purpose of her testimony was to provide a review of the proposed adjustments to revenues, the request for an additional rider in this Cause, and the overall use of riders by the Company.

PUD reviewed all information and testimony provided by the Company in this Cause related to revenue recovery through riders. PUD further reviewed Commission orders, testimony to related areas in prior causes, and work papers relating to PSO. PUD communicated with the Company through email, phone calls, and reviewed responses to data requests.

PUD reviewed the proposed adjustments to base revenue, other revenues and fuel revenues. Except for the PUD's recommendation to reverse the adjustments made to revenues (and costs) related to the System Reliability Rider, PUD has no changes to the Company's proposed revenue adjustments.

Regarding riders, PSO currently has eight riders in place and has requested another, the Environmental Cost Recovery Rider, to recover the costs of compliance. PUD recommends that the overall use of riders be reviewed and evaluation criteria be established for use in determining the need for additional riders. PUD recommends that riders be allowed only if they are used for cost that [*sic*] are: outside of the utilities control; substantial; and unpredictable or volatile. PUD reviewed the existing riders using that recommended criteria and found most would not meet the test.

Upon review of the riders, PUD recommends: the Environmental Cost Recovery (ECR) not be approved and recovery of those costs remain in base rates; closure of the System Hardening Rider (SRR); add language to the Southwest Power Pool Cost Tracker (SPPTC) that would require broader review if annual increase exceeds 50 percent; add language to the Advanced Metering Infrastructure (AMI) to provide [*sic*] date certain for [*sic*] closing rider; add language to the Demand Side Management Cost Recovery Rider (DSMCRR) that would limit the accumulation of lost revenue recovery.

PUD believes these recommendations balance the interests of parties, are fair, just and reasonable, and in the public interest.

<u>Robert C. Thompson</u>

Robert C. Thompson is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Mr. Thompson filed Responsive Testimony on October 14, 2015. The purpose of his testimony was to provide a review of the proposed adjustments in this Cause and the Accounting Exhibit for PSO Cause No. 2001500208 [*sic*].

Mr. Thompson reviewed all information and testimony provided by the Company in this Cause related to his assigned areas of review. In addition, PUD reviewed previously filed testimony in related areas for prior causes, and work papers relating to PSO. Mr. Thompson communicated with the Company through email, phone calls, in-person reviews, reviewed electronic information/data requests and reviewed responses to these requests and those of other parties to this cause.

Mr. Thompson's testimony focuses on the following areas:

Plant in Service: PUD proposes adjustments to update plant in service to the 6-month post test year balance at July 31. PUD's adjustments B-3 increase plant in service included in rate base by $9,557,979.

Environmental Controls: PUD is proposing to include $135,075,111 in environmental control investment incurred at 6 months post test year in rate base.

Accumulated Depreciation: PUD proposes an adjustment to update accumulated depreciation to the 6-month post test year balance at July 31, 2015. PUD's adjustment B-4 increases accumulated depreciation by $39,145,204, which is a decrease to rate base.

Non-AMI (Automated Meter Infrastructure) Meters in Rate Base: PUD proposes adjustments to update regulatory assets to include Non-AMI Meters to the 6-month post test year balance at July 31. PUD's adjustments [*sic*] B-9 increase plant in service included in rate base by $18,262,961.

Cash Working Capital: PUD proposes an adjustment to the cash working capital (CWC), which includes all of PUD's proposed changes to those accounts included within the cash working capital calculation. PUD agrees with the cash working capital methodology which excludes non-cash items such as depreciation, investment tax credit and common equity. PUD's adjustment will decrease cash working capital included in rate base by $186,040.

Accumulated Deferred Income Tax: PUD proposes an adjustment to update accumulated deferred income tax to the 6-month post test year balance at July 31, 2015. PUD's adjustment will decrease accumulated deferred income tax included in rate base by ($39,145,204).

Prepaid Pension Asset: PUD supports the inclusion of $96,864,056 in prepaid pension assets in rate base as proposed by PSO.

Amortization Expense: PUD proposes to adjust the amortization expense to include amortization on Non-AMI meters by $1,749,592.

Factoring Expense: PUD proposes to adjust the factoring expense by ($224,029) to reflect PUD's revenue requirement.

Ad Valorem Tax Expense: PUD proposed to adjust ad valorem tax expense by ($2,133,195).

Interest Synchronization: PUD is proposing an adjustment to the 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 ratepayer's contribution to PSO for interest expense coverage. PUD's adjustment for interest synchronization will decrease the net income before income tax by $2,402,266.

Current Tax Expense: PUD is proposing an adjustment to current income taxes to reflect PUD's adjustments to the operating income statement, including the revenue deficiency, resulting in a net decrease to PSO's operating income of $7,513,020.

Larry Blank – Rate Design/Cost of Service Issues

On October 23, 2015, Dr. Larry Blank filed Responsive Testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") to address the cost of service study and rate design proposals in the direct case of the Public Service Company of Oklahoma ("PSO" or "Company") for Cause No. PUD 201500208. Dr. Blank testifies on the following issues, among others:

- Review of base rate cost of service methodology and rate design filed by PSO;
- Assessment of the proposed Environmental Compliance Rider ("ECR") to including [*sic*] several revisions to the proposed ECR tariff language; and
- Recommendation of a proposed tariff rate schedule for Northeastern Unit 4 Recovery Rider ("NE 4 Rider").

Review of PSO's Cost of Service Study

PSO's filed cost of service study is considered by Dr. Blank to use widely accepted methods and Dr. Blank recommends adoption of these methods and the results. However, after reviewing the proposed base rate increase methodology and rate design, as filed by PSO, Dr. Blank testifies that PSO's proposal for allocating costs deviates from its cost of service study results. PSO's base rate increase methodology does balance the interest of the two largest customer classes; i.e., Service Level 1 ("SL1") and Service Level 2 ("SL2"). SL2 customers will receive an increase somewhat above the cost of service result and SL1 customers will receive an increase somewhat below the cost of service. Dr. Blank's review of PSO's cost allocation found that the Residential class would receive the largest benefit from the Company's proposed rate design. To create a more reasonable cost assignment, Dr. Blank suggests the Commission consider moving a portion of the revenue requirement away from the Commercial and Small Industrial classes to the Residential class.

Environmental Compliance Rider Rate Design

Dr. Blank continues to support the DoD/FEA recommendation that the post-test year adjustments sought by PSO not be included in base rates and rather should be considered in the base rates revenue requirement in the next general rate case rather than through an ECR; however, if the Commission believes the ECR is preferred, then Dr. Blank has provided several recommended modifications to add necessary details and prevent over-recovery. Dr. Blank identifies the following issues in the ECR rate schedule proposed by PSO:

a. Lacks important details on the definition and calculation of "Environmental Costs";

b. Fails to specify the rate of return;

c. Fails to include accumulated depreciation in the calculation;

d. Overstates and fails to specify depreciation rates and expense;

e. Needs to more clearly specify the allocation methodology; and

f. Fails to specify an annual filing for the recalculation of the ECR.

Based on the issues described above, Dr. Blank's testimony, including his Exhibit LB2-1, recommends several adjustments to the ECR tariff language proposed by PSO. The major adjustments are summarized as follows:

a. The components of PSO's "Environmental Costs" equation should include the weighted average cost of capital from the most recent rate case.

b. Dr. Blank also recommends the Environmental Control Plant included in the rider should be limited to plant in service, not construction work in progress. Dr. Blank defines the environmental control plant as the plant in service at Northeastern Unit 3 ("NE 3") and Comanche Power Station ("Comanche")

c. The accumulated depreciation used in the calculation should be based on the effective period for the rider, and not based on historic balances.

d. The depreciation expense should be based on current depreciation rates for NE 3 and Comanche.

e. Provides an annual recalculation filing process.

f. Dr. Blank also provides an alternative recommendation that presents a compromise to the two extremes for environmental cost recovery as suggested by PSO. Dr. Blank's compromise recommendation is the creation of a regulatory asset for the environmental control equipment plant in service at NE 3 and Comanche. Disposition of the regulatory asset should occur in the next general rate case, which should be encouraged soon.

<u>Northeastern Unit 4 Recovery Rider Design</u>

Dr. Blank provides a tariff rate schedule in his Exhibit LB2-2, the NE 4 Rider, for annualized recovery of costs related to NE 4 in an amount of $6,331,684. This amount should be allocated based on the class production allocation ratios for each major rate class within the Oklahoma retail jurisdiction as determined in the cost of service study of the last general rate case.

<u>Summaries of Responsive Testimony of Oklahoma Attorney General</u>

<u>Edwin C. Farrar</u>

Mr. Edwin C. Farrar filed his Rate Design Testimony Summary on October 23, 2015. The purpose of his testimony was to discuss his approval of Public Service Company of Oklahoma's (PSO's) decision to allocate any rate increase resulting from the PSO rate case equally among customer classes, thus mitigating potential rate shock to the residential class.

Mr. Farrar stated that PSO is recommending that its requested rate increase be distributed equally to the customer classes. If PSO's Class Cost of Service Study were the only basis for the distribution of the rate increase, then the residential increase would be significantly higher.

Mr. Farrar stated that in general, the Commission should consider the burden each customer class places on the utility system. A Class Cost of Service Study accomplishes this by classifying costs and then allocated [*sic*] them to each customer class based on the study's parameters.

Mr. Farrar stated that with the significant increase requested in this Cause, he was concerned that a move to a full cost of service base rate for residential customers would result in rate shock, and accordingly, would not be practical at this time. Mr. Farrar stated that PSO made a reasonable proposal to minimize rate shock to residential customers considering the magnitude of the increase requested in this Cause.

Mr. Farrar reserved the right to review issued [*sic*] raised by other parties in this Cause and to address those issues at a later time.

<u>James W. Daniel</u>

James W. Daniel, Vice President of the firm GDS Associates, Inc. ("GDS") and Manager of GDS' office in Austin, Texas, testified on behalf of the Oklahoma Office of the Attorney General. Mr. Daniel's Responsive Testimony addressed PSO's proposal to implement an Environmental Compliance Rider ("ECR") to recover certain environmental compliance costs. His testimony discusses both policy reasons and Public Service Company of Oklahoma ("PSO" or "Company") specific reasons that the Oklahoma Corporation Commission ("OCC" or "Commission") should not approve PSO's proposed ECR.

The Company is proposing to recover the capital costs related to environmental compliance facilities either in base rates or through the proposed ECR. The environmental compliance facilities are related to Northeastern Unit 3 and the Comanche Power Station, and are supposed to go into effect in January 2016 and June 2016, respectively. Since these facilities would go in service more than six months after the end of the test year, the costs do not qualify for base rate recovery in this case.

Mr. Daniel raises numerous policy or general issues as to why the future environmental compliance costs should not be recovered through an automatic rate adjustment clause or rider. These general issues include:

(1) the costs are mostly fixed and stable making them inappropriate for rider treatment and so, if recoverable at all, they should be sought in base rates in a future rate case,
(2) the proposed ECR results in piecemeal ratemaking,
(3) the proposed rider will result in a disincentive for PSO to control costs,
(4) the proposed rider will shift risks from stockholders to ratepayers, and
(5) PSO already recovers a substantial portion of its revenue requirements through riders.

Mr. Daniel also raises PSO-specific problems with the proposed ECR. The specific problems with PSO's proposed ECR include:

(1) the rider would reduce risks to PSO's stockholders without any offsetting adjustment to PSO's proposed return on equity, and
(2) the rider would recover environment compliance capital costs for the Comanche Power Station while those facilities are still under construction.

In addition, should the Commission approve an ECR, the proposed provisions in PSO's ECR Tariff should be modified for the following issues:

(1) the definition of "Environmental Costs" should include a cap on the investment in the facilities,
(2) the true-up provisions should be determined on a customer class specific basis,
(3) the proposed term of the ECR should not be open-ended,
(4) the Class Production Allocator should be updated periodically rather than remain constant, and
(5) there should be a review and approval process for affected parties and the Commission to review future proposed ECR factor filings.

PSO's proposed ECR is fraught with issues and problems and should not be approved by the Commission.

<u>Summary Responsive Rate Design Testimony of Mark E. Garrett</u>

1. As part of its Environmental Compliance Plan ("ECP"), PSO is proposing to recover costs of $44.2 million annual revenue requirement related to environmental compliance facilities that will not be placed in service until 2016. PSO seeks Commission approval of these costs either: (1) by including the costs in base rates, or (2) implementing a new rider, the Environmental Compliance Rider ("ECR") for the recovery of these costs. <u>Both proposals are inappropriate and should be rejected by the Commission.</u>

2. PSO's proposed rate base treatment of the $44.2 million of ECP costs should be rejected because the assets associated with these costs will be placed in service in 2016, well beyond the statutory cut-off for rate base additions, which ended July 31, 2015.

3. PSO's proposed rider recovery of the $44.2 million of ECP costs should be rejected because these costs do not qualify for rider treatment. PSO has not sought pre-approval of ECP costs pursuant to 17 O.S. 286, and PSO's ECP capital asset additions are not the types of costs that are appropriate for rider recovery.

4. PSO has not demonstrated that extraordinary measures are needed, or appropriate, for the recovery of its ECP costs. The ECP costs are not volatile or widely fluctuating costs, nor are they sufficiently significant to impugn the financial integrity of the Company. PSO should seek recovery of these costs through a general rate case proceeding once the facilities are placed in service.

5. If my recommendation is rejected, and PSO's ECR is approved in this docket, I recommend several important changes to the rider. (1) The recovery amount should be reduced by $6.2 million for the O&M adjustment proposed in the Responsive Testimony of OIEC witness Scott Norwood. (2) The recovery amount should be reduced by $7.4 million to remove the return on the stranded Northeastern Unit 4 assets, as discussed in my Responsive Revenue Requirement Testimony, and as set forth in Exhibit MG-2 in that testimony. (3) The rider should not include CWIP recovery for assets not yet placed in service. Oklahoma has consistently not allowed CWIP recovery in rates and it should not now violate its long-standing correct treatment of this issue. (4) The Commission should require PSO to file a rate case within twenty four (24) months after the implementation date of the rider. This is the statutorily prescribed time period for rate case review of riders approved under Oklahoma's pre-approval statute, Title 17 § 286. It would be a reasonable requirement to impose if the ECP rider is approved in this case.

6. PSO's class cost of service study should use a 4CP method for transmission cost allocation to retail customer classes rather than the 12CP method proposed by PSO. In addition, due to the significantly lower revenue requirement recommendations proposed by OIEC, PUD, and the Attorney General in their respective Responsive Testimony addressing Revenue Requirement issues, I recommend taking all customer classes to actual cost of service.

<u>Summary Responsive Rate Design Testimony of Scott Norwood</u>

My name is Scott Norwood. My business address is P.O. Box 30197, Austin, Texas 78755. I am an energy consultant and President of Norwood Energy Consulting, L.L.C. I am testifying on behalf of Oklahoma Industrial Energy Consumers ("OIEC"). OIEC's members are among the largest users of electricity on Public Service Company of Oklahoma's ("PSO" or "Company") system, and therefore are very sensitive to any electric rate increases proposed by PSO. I also filed Responsive Testimony on behalf of OIEC addressing PSO's cost recovery proposals for environmental compliance and production O&M in this Cause on October 14, 2015.

I am an electrical engineer with nearly 30 years of experience in the electric utility industry in the areas of power plant operations, electric resource planning and procurement, and regulatory consulting. I have represented OIEC in regulatory proceedings before the Oklahoma Corporation Commission ("OCC" or "Commission") for nearly 15 years. My resume and a listing of my past testimony [*sic*] are attached as Exhibit SN-1 to my earlier Responsive Testimony filed in the revenue requirement phase of this cause.

The purpose of my testimony is to present my findings and recommendations regarding the allocation of certain replacement energy costs arising from PSO's request for cost recovery for the Company's proposed environmental compliance plan ("ECP") under its settlement agreement with the United States Environmental Protection Agency ("EPA"), the State of Oklahoma and the Sierra Club (hereinafter referred to as the "EPA Settlement" or "Settlement"), which was executed by the parties in October of 2012. My testimony also addresses PSO's proposed retention of 25% of the net revenues associated with the purchase and sale of certain services within the Southwest Power Pool's Integrated Market ("SPP IM"). My findings and recommendations regarding these two issues are explained further below.

Allocation of EPA Settlement Replacement Capacity and Energy Costs

PSO is proposing that it be allowed to recover replacement energy costs resulting from the early retirement of the Company's Northeastern coal units under the EPA Settlement through the Fuel Cost Adjustment ("FCA") Rider. Under this proposed ratemaking treatment, such replacement energy costs would be disproportionately allocated to high load factor customers, who already are bearing a disproportionate share of the increased cost [*sic*] and risk [*sic*] arising from the loss of fuel diversity under the Settlement. To address these concerns regarding the inequitable allocation of replacement energy costs arising from the EPA Settlement, I recommend that all energy costs purchased under the Calpine, Green County and Eastman Cogeneration purchased power agreements be allocated on a production demand basis, and recovered through PSO's FCA Rider. Prospectively, all energy costs of future generating resources acquired by PSO to replace the retired Northeastern coal units should also be allocated on a production demand basis to ensure more equitable sharing of costs of the EPA Settlement among customers.

SPP Integrated Market Net Revenues

PSO's existing FCA Rider allows the Company to retain 25% of the margins earned from off-system sales of electricity; however, it does not explicitly address the treatment of the net revenues associated with PSO's sale and purchases of certain services, such as spinning reserves, supplemental reserves, congestion and other services, in the SPP IM. These SPP IM net revenues are not necessarily net profits from sale of electricity, but rather represent the net difference between amounts PSO earned from the sale of such services and the amount the Company paid for such services in each month. Last year, the net revenues earned from such transactions averaged approximately $600,000 per month, and the Company has included such amounts as off-system sales and retained 25% of the Oklahoma retail share of such margins, while crediting the remainder of the margins against retail fuel expenses. PSO has elected to participate in the SPP IM, SPP has assumed control of the market operational decisions that lead to the purchase and sale of the services at issue, and SPP and PSO are compensated for costs associated with administration of the SPP IM. There is no apparent basis for sharing net revenues from such transactions with the Company as if they were profits that otherwise would not be earned. For these reasons, I recommend that the FCA Rider be modified to exclude from off-system sales margin sharing any net revenues derived from PSO's purchase and sale of SPP IM services.

Cost of Service/Rate Design Summary Responsive Testimony of Jeremy K. Schwartz

Jeremy Schwartz is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. Mr. Schwartz testified to the areas of cost of service ("COS") and rate design in Cause No. PUD 201500208.

Mr. Schwartz reviewed all information and testimony provided by the Company in this Cause related to COS, rate design, and weather normalization. Mr. Schwartz further reviewed Commission orders, testimony related to areas in prior causes, and work papers relating to PSO. Mr. Schwartz communicated with the Company through email, phone calls, in-person reviews, electronic information/data requests and reviewed responses to these requests.

Mr. Schwartz stated that based on the results of PUD's inputs to PSO's COSS [*sic*], retail customers would be allocated an increase of $58,132,537[13] excluding miscellaneous revenue, while the federal jurisdiction would be allocated a total of $1,235,810.

Regarding rate design, Mr. Schwartz stated that he believes there is a necessary increase in revenue requirement for the Company to continue maintaining safe and reliable service to consumers. The total increase is allocated to certain classes based on the results of a COSS. These results show the costs that each class of customers places on the system. Mr. Schwartz stated that he has designed rates based on the necessary revenue allocations discussed previously in his testimony.

Overall, Mr. Schwartz recommended the Commission approve the following:

- The Company is to conduct a Minimum System study to identify and allocate customer-related costs for distribution assets before proposing a change to any class base service charge in future causes before this Commission;
- The revenue distribution and rate design described in this testimony; and,
- A separate line item on consumer's bills to show the breakdown of costs that can be attributed to managerial decisions of the Company and those that are due to outside action.

Mr. Schwartz believes these proposals are fair, just, and reasonable to both the Company and its ratepayers.

<u>Summary of Responsive Testimony of John Athas</u>

On behalf of the Oklahoma Hospital Association ("OHA"), Mr. John G. Athas submitted Responsive Testimony commenting on the rate design and revenue allocation approach proposed by the testimony of Jennifer L. Jackson for Public Service of Oklahoma ("PSO"). Mr. Athas is a Principal Consultant and Treasurer of La Capra Associates, Inc., with 30 years of experience in areas including rates and pricing, strategic planning, integrated resource planning, generation planning, economic and financial analysis, marketing, wholesale power market analysis and forecasting, and electric power retail marketing.

The OHA represents the interests and views of more than 135 member hospitals and health systems across the state of Oklahoma. Inputs into the costs of providing healthcare services, including electricity, are matters of concern to the OHA since costs have a direct effect on the OHA's primary objective of promoting the health and welfare of all Oklahomans by leading and assisting its member organizations in providing high quality, safe, and valued health care services. Several of the OHA members receive service from PSO, particularly in the GS, PL, SL3 and SL2 rate classes.

In order to meet the Company's desired revenue request, Ms. Jackson has proposed to increase each rate class by the same percentage, and has proposed no changes in rate design in this case. Mr. Athas urges the Commission to reject this proposal since PSO has performed an

[13] The difference between this figure and PUD's Accounting Exhibit base rate revenue increase is due to a ($4,511,027) change in other revenues and PUD's proposal to include the System Reliability Rider in base rates.

allocated cost of service study that demonstrates that some classes are paying more than costs, and some less than costs, in some cases by substantial margins. PSO is proposing to simply increase existing rate components equally, without consideration of its underlying costs. At an equalized return, however, the proposed revenue requirement and the proposed rates for each customer class would be designed to recover the cost to serve each respective class.

The Company has not provided any reasonable or objective rationale for its approach to the proposed increase and instead supports its approach by subjectively determining that the increases to certain classes would be "too much", but the increases to others are acceptable, and that this approach has been followed in the past. When some classes pay more than their allocated share of costs, they are subsidizing other rate classes. While Ms. Jackson acknowledges that equalized rates of return across all classes would be ideal, PSO's approach to revenue allocation will result in continuing to undercharge certain rate classes and overcharge others. The Company has not attempted to move class revenues closer to class costs in this rate case, and it does not propose any plan for movement toward equal rates of return in the future. The divergence in the class rates of return would appear to be accepted by the Company as a permanent feature of its rate design approach.

Mr. Athas recommends that PSO's approach, equal percentage increases to each class and rate schedule, be rejected. Instead, increases to each class should vary based on the information provided by the allocated cost of service study, with some progress made towards achieving equalized rates of return. If the Company's allowed revenue increase is much smaller than the request, it should be possible to move rate classes to equal rates of return without excessive rate increases. Even if the overall increase is quite low, Mr. Athas believes that the increase to some specific rate schedules within rate classes may need to be moderated. This result can be accomplished relatively easily by limiting the decreases suggested by the cost of service study and not decreasing any rate schedules or by collecting the missing revenue from other rate schedules within the same rate class. In general, rate schedules which show current rates of return significantly below the average should receive higher than average increases, as long as those increases are not a large multiple of the average increase. Classes with average or higher than average rates of return should receive no or low increases.

<u>Summary of the Responsive Revenue Requirements Testimony and Exhibits of Steve W. Chriss</u>

Steve W. Chriss filed Responsive Revenue Requirements Testimony on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., (collectively "Walmart"). Mr. Chriss is Senior Manager, Energy Regulatory Analysis, with Wal-Mart Stores, Inc.

Walmart operates 133 retail units and employs 33,561 associates in Oklahoma. In the fiscal year ending 2015, Walmart purchased $677.7 million worth of goods and services from Oklahoma-based suppliers, supporting 18,438 supplier jobs. Walmart has 47 stores 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 ("LPL SL3").

Mr. Chriss' recommendations are as follows:

1) The Commission should thoroughly and carefully consider the customer impact in examining the requested revenue requirement and return on equity

("ROE"), in addition to all other facets of this case, to ensure that any increase in the Company's rates is the minimum amount necessary to provide adequate and reliable service, while also providing an opportunity to earn a reasonable return.

2) The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of (a) the customer impact of the resulting revenue requirement increases, (b) recent rate case ROEs approved in the region surrounding Oklahoma, and (c) recent rate case ROEs approved by commissions nationwide.

Rebuttal Testimony Summary of Scott Norwood

My name is Scott Norwood. My business address is P.O. Box 30197, Austin, Texas 78755. I am an energy consultant and President of Norwood Energy Consulting, L.L.C. I am testifying on behalf of Oklahoma Industrial Energy Consumers ("OIEC"). OIEC's members are among the largest users of electricity on Public Service Company of Oklahoma's ("PSO" or "Company") system, and therefore are very sensitive to any electric rate increases proposed by PSO. I also filed Responsive Testimony on behalf of OIEC addressing PSO's cost recovery proposals for environmental compliance and production O&M in this Cause on October 14, 2015. I also filed testimony addressing certain rate design and cost allocation issues in this Cause on October 23, 2015.

I am an electrical engineer with nearly 30 years of experience in the electric utility industry in the areas of power plant operations, electric resource planning and procurement, and regulatory consulting. I have represented OIEC in regulatory proceedings before the Oklahoma Corporation Commission ("OCC" or "Commission") for nearly 15 years. My resume and a listing of my past testimony are attached as Exhibit SN-1 to my Responsive Testimony filed in the revenue requirement phase of this cause.

The purpose of my Rebuttal Testimony is to respond to certain conclusions and recommendations presented in the Responsive Testimony of OCC Staff witness Dr. Craig Roach regarding PSO's environmental compliance plan ("ECP") pursuant to the Company's settlement agreement with the United States Environmental Protection Agency ("EPA"), the State of Oklahoma and the Sierra Club (hereinafter referred to as the "EPA Settlement" or "Settlement").

PRUDENCE OF EPA SETTLEMENT

Dr. Roach asserts in his Responsive Testimony that PSO demonstrated the prudence of the EPA Settlement through its analysis in OCC Cause No. PUD 201200054. I disagree with Dr. Roach on this issue. In fact, as discussed in my Responsive and Rebuttal Testimony, PSO's own analyses as presented in PUD 201200054 demonstrated that the cost of the EPA Settlement was expected to be much higher than the Coal Retrofit alternative under virtually all scenarios evaluated by the Company.

I agree with Dr. Roach that utilities such as PSO should be held accountable to reevaluate the prudence of major investments in light of material changes. As explained in my Rebuttal Testimony, since May of 2013, when PSO last updated its analysis of the EPA Settlement, there have been at least two material changes that impact the forecasted costs and benefits of the Settlement. First, PSO entered into two new power purchase agreements ("PPAs") to help replace the 470 MW of capacity lost due to the early retirement of Northeastern Unit 4. The second material change that has occurred since PSO last updated its economic analysis of the EPA Settlement is the enactment of the EPA's final Clean Power Plan ("CPP"), which governs the regulation of carbon emissions from existing power plants in the future. Unfortunately, and as noted by Dr. Roach on page 33 of his Responsive Testimony, the Company did not update its analysis to assess the impacts of the final CPP or new PPAs on the Company's choice of the EPA Settlement over the Coal Retrofit alternative. My Rebuttal Testimony demonstrates that, if PSO had updated its economic analyses to reflect the final CPP and new PPAs that were signed to replace capacity lost due to retirement of Northeastern 4, the Coal Retrofit alternative would be a much lower cost option when compared to the EPA Settlement in every scenario evaluated by PSO.

In my Rebuttal Testimony I explain that I agree with Dr. Roach's recommendation that the Commission not rule on the prudence of the planned retirement of Northeastern Unit 3 in 2026 until a hearing is held to examine the reasonableness of that decision in or about 2020. This recommendation is reasonable and appropriate in light of the fact that PSO entered into the EPA Settlement without consulting the Commission and without including a regulatory out provision in the event changes in regulations or other factors justified [*sic*] continued operations of its Northeastern coal units.

CLEAN POWER PLAN/ENVIRONMENTAL RISK

I disagree with Dr. Roach's testimony that the EPA Settlement has the lowest risk adjusted cost due to the risk that pending, likely and potential future regulations could lead to the early shutdown of the Northeastern units. Dr. Roach has admitted that it is not possible to accurately predict the nature or compliance cost of future environmental regulations on PSO's coal plants at this time and that for this reason he has performed no quantitative analysis to support his opinion that future regulations would likely lead to early retirement of PSO's coal units. Moreover, as explained in my Rebuttal Testimony, other utility industry experts disagree with Dr. Roach's opinion regarding the future risk of early retirement of relatively new and efficient large coal units such as PSO's Northeastern units. In fact, in the same general timeframe that PSO was evaluating the Coal Retrofit alternative to the EPA Settlement, AEP witnesses presented testimony in regulatory cases in Arkansas and Virginia that coal plants similar in size and vintage to the Northeastern coal units are likely to be able to operate for 60 years or more if equipped with scrubbers, and PSO's affiliate Southwestern Electric Power Company ("SWEPCO") sought and obtained approval from regulators in Texas to construct the new $2 billion Turk coal-fired generating unit.

In addition, earlier this year Oklahoma Gas & Electric Company ("OG&E") filed an Application with the Commission seeking approval of an ECP that would retrofit and continue operations of three of the Company's five existing coal-fired generating units, which are also similar in size and vintage to PSO's Northeastern coal units. Dr. Roach and I both recommended that the Commission approve OG&E's ECP with certain conditions. In explaining his reasons for supporting OG&E's proposal, Dr. Roach noted that the Company's compliance plan had appropriately offered a diversified portfolio of actions in the face of significant uncertainty that exists with regard to future environmental regulations and natural gas prices.

I also disagree with Dr. Roach's testimony that [*sic*] EPA's final CPP has further increased the risk that PSO's Northeastern coal units would be forced into early retirement. It appears that Dr. Roach focused on the CO2 rate-based goals of the final CPP, and did not consider whether PSO could meet the alternative mass-based goals of the CPP, which require a 23% reduction in total CO2 mass emissions by 2030. In fact, the cost of compliance with the final CPP's carbon mass-based goals appears to be far lower than [*sic*] cost implied by the carbon tax proxy included in PSO's economic analysis of the Coal Retrofit alternative. Given this, contrary to Dr. Roach's testimony, the final CPP reflects a significantly lower cost of compliance with carbon emissions regulations than assumed by PSO's economic analyses of the Coal Retrofit compliance option, and therefore decreases the prospect that the Northeastern coal units would be forced into early retirement. In fact, as explained in my Rebuttal Testimony, with the reduction in the generation levels of PSO's existing gas-fired units that has already occurred since 2012, and the increase in wind energy purchases and energy efficiency savings currently forecasted by PSO, the Company would achieve a 35% reduction in CO2 emissions from the 2012 base year emissions level for its Oklahoma system by 2030, if it implemented the Coal Retrofit compliance plan.

These results indicate that PSO would more than meet the 23% carbon emissions reduction target of the CPP under the Coal Retrofit alternative (i.e., without retiring coal units) without further mitigation costs. This means that there is no justification for the $3.3 billion of carbon taxes that PSO included in its analysis of the Coal Retrofit alternative as a proxy for the cost of compliance with future carbon regulations. As shown in Table R2 on page 6 of my Rebuttal Testimony, this in turn means that the economic advantage of the Coal Retrofit option over the EPA Settlement is more than $1.5 billion greater on a nominal basis, and $371 million on a present value basis, than originally estimated by PSO. For these reasons, Dr. Roach's testimony that the CPP increases the risk of early shutdown of the Northeastern coal units is unfounded.

As noted in my Rebuttal Testimony, OG&E officials have recently indicated that it appears that the final CPP will have a relatively modest impact on Oklahoma's utilities and that the Company expects to be able to comply with the 23% mass emissions goal of the final CPP while maintaining 3 of its five coal-fired plants in service. It appears that Oklahoma's abundant supply of relatively low-cost wind energy is a major reason why the final CPP is expected to have a relatively modest cost impact on Oklahoma's utilities.

MATERIALITY OF COAL RETROFIT ECONOMIC ADVANTAGE

I disagree with Dr. Roach's testimony that the estimated costs of the EPA Settlement and Coal Retrofit compliance alternative were very close. As explained in my Rebuttal Testimony, in reaching this conclusion it appears that Dr. Roach has relied upon PSO's calculations of the EPA Settlement and Coal Retrofit compliance plan costs, which understate the economic advantage of the Coal Retrofit option by approximately $1.6 billion on a nominal basis, and by approximately $400 million on a present value basis, by failing to include costs of two new replacement PPAs and by including carbon compliance costs which are no longer valid under the final CPP. Moreover, PSO's calculations improperly understate the percentage cost advantage of the Coal Retrofit alternative over the EPA Settlement by including fixed costs of resources that do not change from case to case in the "total system cost" that was used as the denominator in calculating the "percentage cost difference" between the two cases. Once these problems are corrected, and adjustments are made to reflect the costs of replacement PPAs which were not included in PSO's analysis, and to correct PSO's invalid carbon compliance cost forecast, the advantage of the Coal Retrofit option over the EPA Settlement would be approximately 14%. This is clearly a significant difference that reflects a distinct economic advantage for the Coal Retrofit option over the EPA Settlement. It does not appear that Dr. Roach considered these problems underlying PSO's percentage difference calculations in reaching his conclusion that the economic advantage of the Coal Retrofit option over the Settlement was insignificant.

ACCOUNTABILITY FOR COST AND PERFORMANCE ESTIMATES

I agree with Dr. Roach's testimony that utilities such as PSO should be held accountable for cost and performance estimates that are used to prove prudence of major investments. As noted by Dr. Roach, this policy has been implemented by regulators in other jurisdictions, and it is particularly appropriate in this case since PSO's own base case analysis indicates that the cost of implementing the selected EPA Settlement is approximately $1.9 billion higher than the Coal Retrofit compliance option. In addition to the cost and performance factors identified by Dr. Roach, PSO should also be held accountable for its forecasts of carbon taxes and replacement power costs for Northeastern Unit 4. As discussed earlier in my testimony, PSO's failure to properly adjust its analysis to reflect the cost of new PPAs and the fact that carbon taxes are no longer valid served to understate the cost advantage of the Coal Retrofit alternative over the EPA Settlement by approximately $31 million on a present value basis. As explained in my Rebuttal Testimony, if the Commission does not adopt OIEC's primary recommendation to disallow all capacity costs of the Calpine, Green County [*sic*] and Eastman Cogeneration PPAs to account for the imprudence of the EPA Settlement, I alternatively recommend that the capacity costs of the Green Country and Eastman Cogeneration PPAs be disallowed, since PSO entered into to [*sic*] these transactions in order to replace capacity lost due to the retirement of Northeastern Unit 4 and never considered the costs of such PPAs in its economic analyses of the EPA Settlement and Coal Retrofit alternative. The capacity costs of these PPAs represent only a small percentage of the extra costs that would otherwise be charged to PSO's customers as a result of the Company's use of unreasonable assumptions to support selection of the EPA Settlement over the Coal Retrofit alternative.

OTHER COST RECOVERY ISSUES

I agree with certain aspects of Dr. Roach's recommendation that approved costs of PSO's environmental compliance plan should be recovered through base rates, subject to the conditions outlined in OIEC witness Garrett's Responsive Testimony, and not through the Company's proposed ECR Rider or FCA Rider. In particular, I object to the Company's proposal to recover certain environmental consumables costs through the FCA Rider due to the fact that non-fuel costs generally should not be recovered through the FCA Rider. However, if the Commission determines that it is appropriate for PSO to recover such costs through the Company's FCA Rider, these costs should be allocated on a demand basis to ensure that large energy users are not required to pay a disproportionately large share of PSO's environmental compliance costs.

Finally, I disagree with Dr. Roach's recommendation that PSO should be allowed to seek approval of certain environmental compliance investments and costs of new PPAs through its rebuttal case. The Company had full opportunity to support its request for cost recovery for these items in its prefiled Direct Testimony, and should not be allowed to present supporting evidence for the first time through its Rebuttal Testimony.

Rebuttal Testimony Summary of Mark E. Garrett

SUMMARY OF RECOMMENDATIONS

1. In addition to OIEC's revenue requirement recommendations, the Commission should also accept the following important revenue requirement adjustments proposed by the Attorney General and Staff witnesses:

    A. The Commission should accept the Attorney General's recommendation to update revenues to the statutory 6-month post test year cutoff date to recognize load growth on the system. When investment levels are updated to the 6-month cutoff period, revenues must be updated as well. This adjustment reduces PSO's requested rate increase by **$7,069,272.**

    B. The Commission should accept Staff's recommendation to update payroll expense to the statutory 6-month post test year cutoff date for known and measurable changes. This adjustment reduces PSO's requested rate increase by **$1,604,468.**

    C. The Commission should accept Staff's recommended depreciation rates for distribution assets. OIEC's depreciation expert only addressed the depreciation rates for transmission, generation and general assets. The Commission should add Staff's distribution depreciation rate impacts to OIEC's depreciation rate recommendations. This adjustment reduces PSO's requested rate increase by **$9,186,373.**

2. The Commission should reject Staff's recommendation to include in rates Construction Work in Progress ("CWIP") associated with PSO's Environmental Compliance Plan ("ECP") at July 31, 2015, the statutory 6-month cutoff date. The Commission's long-standing policy is that CWIP at the 6-month post test year cutoff date should be excluded from rate base because these facilities that are not yet in service and, therefore, not yet used and useful. In the 20-year period since the enactment of the 6-month post-test year in Oklahoma in Title 17 § 284, the Oklahoma Commission has never, to my knowledge, ordered the inclusion of CWIP in rates. In my opinion, there is not sufficient evidence in this case to warrant a departure from that long-standing and proper ratemaking policy now. Instead, the Commission should require PSO to file an application for ECP cost recovery in a general rate case proceeding once the facilities have been placed in service.

Summary of the Rebuttal Testimony of Jennifer L. Jackson

Jennifer L. Jackson, Regulatory Consultant in Regulated Pricing and Analysis, part of the American Electric Power Service Corporation (AEPSC) Regulatory Services Department, provided Rebuttal Testimony on behalf of Public Service Company of Oklahoma (PSO or Company). Ms. Jackson's Rebuttal Testimony addressed recommendations made by various parties in the area of revenue distribution and rate design. She addressed the following rate design recommendations made by the following witnesses:

- Oklahoma Hospital Association (OHA) witness John G. Athas regarding his recommendations and his analysis of PSO's proposal;
- Oklahoma Industrial Energy Consumers (OIEC) witnesses Mark E. Garrett and Scott Norwood regarding the industrial rate design; and
- Oklahoma Corporation Commission (OCC or Commission) Public Utility Division (PUD) witness Jeremy K. Schwartz regarding the breakdown of information on customer bills.

According to Ms. Jackson, PSO has proposed to distribute the retail base rate revenue requirement change needed to achieve a system average return of 7.60 percent: a 16.25% change in base rates, on an equal percentage basis to all customer classes. The parties filing Responsive Testimony in the Cost-of-Service/Rate Design (COS/RD) phase all make slightly different recommendations regarding how to distribute the proposed revenue increase to the classes. The following parties made revenue distribution recommendations in the COS/RD phase: The OCC PUD, Attorney General (AG), Department of Defense and Other Federal Executive Agencies (DOD), OHA, OIEC, and Walmart.

Ms. Jackson testifies that the parties' recommendations on revenue distribution fall into two categories; those that favor some form of moderation in base rate increase and those that believe strict adherence to the cost-of-service study results are the most appropriate way to distribute the proposed revenue change. All parties with the exception of OIEC make revenue distribution recommendations that contain some form of moderation in the distribution of the revenue increase, including PSO. Ms. Jackson testifies that the revenue distribution recommendations made by the parties are not necessarily wrong and that the majority of the COS/RD testimonies recognize that while all classes should move toward paying the cost of providing the class electric service, that goal is sometimes in conflict with other rate design goals including, stability of rates and customer impact.

Ms. Jackson further testifies that PSO has the goal of moving classes toward paying the cost of providing electric service. In this case, PSO allocated the costs and designed the rates to recover the environmental compliance costs included in the proposed Environmental Compliance Rider (ECR) (or base rate proposal) and the fuel rider at parity and made some movement for most classes towards an equity return for the base rate portion of the proposed increase by increasing each class by the system average percentage change.

According to Ms. Jackson, PSO has proposed to allocate the environmental compliance costs, including the associated fuel changes, based on the class demand or kWh allocators, meaning, that 48% of the total increase request was assigned at parity among the classes. The base rate increase, the other approximately 52% of the total increase, was spread with regard to moderation in overall customer impact and positive movement in class relative rates of return. (The proposed ECR rider $44.2 million plus the estimated consumables and production cost of $39.2 million are 48.4% of the total increase of $172.2 million as proposed by PSO as shown in the filed direct testimony Exhibit JLJ-1).

Ms. Jackson testifies that had PSO proposed that each major rate class be assigned the base rate increase at an equity return for the class, including the environmental rider and fuel requests, the Residential and Lighting classes would have had a total bill impact greater than the system average base rate increase of 16.25%. That scenario, in this case, was deemed too large an impact on those customer classes. Therefore, PSO determined that an equal spread of the total system average base rate increase was the appropriate method of spreading the proposed base rate increase to the customer classes.

Ms. Jackson further testifies that given the base rate increase request, and the fact that the environmental compliance costs and associated fuel changes were assigned to the classes without subsidy, PSO still recommends using the proposed base rate revenue distribution to moderate residential and lighting class total bill impacts.

Ms. Jackson addresses OHA witness Athas's [*sic*] statement that without the benefit of a marginal cost study, he does not know the specifics about the additional cost of summer use and indicates that a marginal cost study is the only way to evaluate the cost of peak demand. Ms. Jackson testifies that PSO uses a four coincident peak average and excess (4CP A&E) allocation methodology for the jurisdictional and class allocation of demand-related production costs. Ms. Jackson states that as discussed by PSO witness John Aaron, the 4CP A&E methodology reasonably assigns costs on the basis of system usage reflecting both an average demand component and an excess demand component. The peak demands for the summer months of June through September are consistently the highest monthly peak demands incurred on the system. The summer coincident peak demands are then used in the development of the 4 coincident peaks (4CP) component of the 4CP average and excess (4CP A&E) allocation factor. The excess component of the 4CP A&E, calculated as the 4CP peak demand less the average demand, recognizes the additional cost responsibility that should be assigned to those customers who place a peak demand on the system that is in excess of their average demand. The excess production demand is used to indicate the additional cost of class peak demand need.

According to Ms. Jackson, the results of the cost-of-service study influence the proposed revenue distribution. The proposed revenue distribution is used to adjust the current seasonal rates under each legacy rate structure. PSO has not proposed to change the structure of its current rate schedules. The structure of the rate schedules is based on seasonality so the framework for each rate schedule has already been deemed reasonable by the Commission. The current rate structures have been set to provide price signals to customers that indicate as usage increases in the on-peak period (inclining kWh blocks) or as efficiency of usage goes down (hours of use kWh structure) or as peak demand is required (time-of-day rates and peak demand ratchets) the price for service is greater. PSO has proposed to retain the current rate structures and incorporate the proposed increase in base rates in a way that minimizes wide variations in customer impact due to the requested increase.

Ms. Jackson addresses OIEC witness Garrett's disagreement with PSO's proposed use of a 12 coincident peak (12CP) to allocate transmission costs to the retail classes. Mr. Garrett believes that the 12CP penalizes industrial customers who have shifted load to the off-peak period in response to the pricing in the industrial rate schedule.

Ms. Jackson testifies that the industrial rate design includes two demand-based billing charges. The second demand-billing unit is based on the monthly maximum demand occurring during each of the twelve months. The maximum demand charge is non-seasonal and not ratcheted. The peak demand charge generally captures the generation demand component and a portion of the transmission cost with the monthly maximum demand charge recovering the remaining transmission cost and any distribution costs associated with the industrial classes. Mr. Garrett also fails to recognize that the on-peak time period for the ratcheted peak demand charge included in the industrial rate schedule is between the hours of 2 p.m. to 9 p.m. during the on-peak season (the months of June through September for industrials). The time-of-day structure of the industrial rate schedule signals customers to shift outside of the on-peak period window during the on-peak season and not necessarily to shift from season to season.

Ms. Jacksons [*sic*] testifies that transmission costs for the retail classes range from approximately 9% to 11% of the total bill and therefore, represent a smaller percentage of total cost. In addition, the LPL billing unit for the Southwest Power Pool Transmission Cost Tariff (SPPTC), which recovers costs associated with Southwest Power Pool transmission base plan projects, is based on the monthly maximum demand-billing unit, not the ratcheted peak demand.

According to Ms. Jackson, Mr. Garrett's argument with regards to the rejection of the 12CP based on faulty price signaling to the industrial classes simply does not reflect the current or proposed design of the industrial rates.

Ms. Jackson addresses OIEC witness Norwood's statement that high load factor customers are disproportionately affected under PSO's fuel replacement proposal. Ms. Jackson testifies that high load factor customers are not disproportionately affected. As can be seen by the results of the revenue distribution, EXHIBIT JLJ-1, the Industrial class of customers taking service under the LPL 1-3 rate schedules, each have a lower than average total bill impact under PSO's base rate and fuel proposal.

Rate Class	Total Bill Impact
Residential Total	14.82%
Commercial Total	13.35%
Total Lighting	13.82%
LPL 3 Total	11.36%
LPL 2 Total	11.35%
LPL 1 Total	10.66%
Total Industrial	11.28%
Total Retail	13.56%

Ms. Jackson also responds to PUD witness Schwartz's recommendation that parties choose one of the three options presented in his testimony for changing the information currently detailed on customer bills. Mr. Schwartz recommends showing, on a separate line on the customer's bill, how much of each customer's bill is specifically related to federally-mandated environmental compliance, in either a dollar form or in a percentage-of-bill format. Mr. Schwartz indicates that his recommendation would aid consumer knowledge to allow customers to identify which costs are due to changes made at the managerial discretion of the Company and those that are significantly caused by outside sources.

Ms. Jackson testifies that while she agrees that providing customers with information about the causes of rate changes is important, she does not agree that PUD's recommendation to make changes to PSO's bills is a good method to accomplish this communication because there are better methods to communicate the reasons for PSO's change in rates, including those associated with compliance with new environmental standards. This type of information is already communicated through PSO's current processes. These include PSO issuing a press release, which is picked up by various news sources and communicated to customers. Also, PSO customer service representatives provide information to customers through direct face-to-face meetings, through emails, and by making themselves available to answer questions in the various communities.

In addition, information is provided on PSO's web site PSOklahoma.com, and PSO's customer solutions center is available to customers who may call with questions about the impacts of the rate change. Every month's current bill has a message that states that a detailed copy of rate schedules will be furnished upon request. Furthermore, specific rate schedule information is communicated each year as part of a bill insert process.

Ms. Jackson further testifies that the option to identify in dollar or percentage form the amount of each customer's monthly bill directly related to EPA action would only be partially accomplished if the separate ECR rider was approved for environmental compliance costs. Without a separate rider factor, the costs of environmental compliance would be bundled with all other base rate costs recovered through usage charges that are subject to seasonal rates, inclining and declining kWh rates, load-factor based rates, and combination demand and energy rates, for example. Further, the proposed environmental costs are also reflected in the cost of consumables, replacement power, fuel switches, carrying charges for NOx controls, etc. Another option was to include, on the customer's bill, a class average increase to a class's bill due to cost increases through EPA action. According to Ms. Jackson, this option would be the easiest to accomplish but, ultimately, this percentage may be meaningless as other portions of the customer's bill adjust over time, such as fuel and other riders with periodic rate updates.

In summary, Ms. Jackson testifies that PSO carefully plans the format of the customer bill in order to give accurate, timely, and useful information about each customer's usage and the cost to the customer. Based on PSO's past experience, adding another line item as PUD recommends, although well intentioned, will simply cause customer confusion about the bill. PSO's existing customer communication methods are much more effective.

<u>Summary of the Rebuttal Testimony of Andrew R. Carlin</u>

Mr. Andrew R. Carlin, Director of Compensation & Executive Benefits for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of Public Service Company of Oklahoma (PSO or Company) [*sic*] offers this summary of his Rebuttal Testimony which responded to recommendations by other parties to this case associated with PSO's recovery of certain employee payroll costs that make up employee total compensation.

I discussed and disputed the individual mischaracterizations made by other parties (Oklahoma Corporation Commission Public Utility Division (OCC PUD) Staff witness David J. Garrett (D. Garrett), Oklahoma Attorney General (AG) witness Edwin C. Farrar (Farrar), and Oklahoma Industrial Energy Consumers (OIEC) witness Mark E. Garrett (M. Garrett)), each of whom seeks to reduce PSO's reasonable cost of service and rate base by eliminating the variable portion of employee compensation. Most importantly, I discussed the fact that no party in this Cause disputes that the total compensation package provided by the Companies to its employees is fair, market-competitive, reasonable and customary. Further, no party has disputed the need for the Companies to provide this market competitive compensation in order to attract and retain a suitably skilled and experienced workforce that efficiently and effectively provides quality electric service to customers.

Certain parties primarily criticize the incentive compensation goals as benefiting both customers and shareholders - which is their basis for the cost disallowances. This Rebuttal Testimony shows that the Companies' variable incentive compensation portion of employee pay is a cost of doing business, provides highly substantial benefits to customers and very limited benefits to shareholders beyond those that have already been captured and passed on to customers in this and previous rate case proceedings.

<u>Annual Incentive Compensation</u>

Financially-based incentive compensation provides many benefits to customers in addition to being a critical component of a market-competitive compensation package.

- It promotes the efficient use of financial resources and cost control, which directly benefits customers by helping to keep rates low.

- It encourages the Companies' management and other employees to pursue investments that benefit shareholders and customers alike, such as automated meter reading technology. Without financially-based incentive compensation, an employee's personal financial interests would be overwhelmingly tied to operating performance and their longevity in their position, which would discourage prudent risk taking. This would send a clear signal to employees at all levels that they should avoid taking on any financial risk because doing so could lead to the loss of their job and there would not be a commensurate upside compensation opportunity.

- It improves the Companies' financial performance without increasing employee compensation expense. This benefits customers continually in future rate cases.

- It is an effective tool for communicating financial objectives to employees, motivating their achievement and aligning employee efforts. This, in turn, helps create a high-performance culture focused on cost that improves employee engagement and is linked to higher performance in all areas.

- It creates a joint purpose that helps eliminate manager versus subordinate and labor versus management mentalities that impede performance.

- It is an expense that varies based on the performance of the Companies, which also reduces earnings volatility, reduces the Companies' cost of capital and reduces the frequency and extent of changes in the size of the Companies' work force.

It attracts, retains and motivates high-performing employees because such employees are more likely to be attracted to a company with a high-performing culture and those employees willing to extend the discretionary effort it takes to succeed in such as [*sic*] culture are more likely to be retained.

The statement from M. Garrett (p. 25) that "the financial benefit should provide ample funds from which to make the payment" grossly mischaracterizes the Companies' annual incentive compensation program by implying that its cost should be offset by incentive driven earnings increases in order for it to be beneficial to customers. This would be proper for annual incentive compensation plans used as 'bonus' payments, which are paid on top of an already market competitive compensation program. This is entirely not the case with the Company's plans. The Companies' employee incentive plans are not an additional cost. The incentive compensation portion of pay is included as part of the total cash compensation or sum of an employee's compensation package as shown in multiple survey results (Exhibits ARC-D3 and ARC-D4).

The Companies use incentive compensation, as part of a market competitive compensation package, to encourage the development of a high performance culture that has potentially long lasting benefits that develop over many years. Financial performance measures in particular encourage cost control at all levels of the organization through the development of this high performance culture. The substantial value that annual incentive compensation has produced over the many years that the Companies have utilized it, has been and will continue to be captured in rates through this and previous rate case proceedings.

The prevalence of incentive compensation is extremely high with U.S. industrial companies, and not just within the electric utility industry. Companies nationwide utilize incentive compensation, which effectively serves to balance customer and shareholder interests regardless of whether this is a stated objective. In fact, some of PSO's largest retail customers have incentive compensation plans. Additionally, the incentive compensation that PSO has requested to be included in its cost of service is not additional compensation; rather, it is a component and included as part of a market competitive compensation package. Neither the level of the Companies' compensation package nor the need to provide market competitive compensation to employees is disputed in this case.

Witness D. Garrett entirely ignores the benefits that the financial components of the Companies' annual incentive compensation provide to customers. Among other benefits, these measures effectively communicate to employees that it is imperative to maintain strong financial discipline. This directly encourages cost control, which benefits customers.

The use of financially-based incentive compensation provides many benefits to customers in addition to being a critical component of an employee compensation package.

- It promotes the efficient use of financial resources and cost control, which directly benefits customers by helping to keep rates low.
- It encourages the Companies' management and other employees to pursue investments that benefit shareholders and customers alike, such as automated meter reading technology.

- It improves the Companies' financial performance without increasing compensation expense in comparison to providing market-competitive compensation through base pay alone. This benefits customers continually in future rate cases.

- It is an effective tool for communicating objectives to employees, motivating their achievement and aligning employee efforts towards the achievement of these objectives. This, in turn, helps create a high-performance corporate culture focused on cost that improves employee engagement and is linked to higher performance in all areas.

- It creates a joint purpose that helps eliminate manager versus subordinate and labor versus management mentalities that impede performance.

- It is an expense that varies based on the performance of the Companies, which also reduces earnings volatility, reduces the Companies' cost of capital and reduces the frequency and extent of changes in the size of the Companies' work force.

- It attracts, retains and motivates high-performing employees because such employees are more likely to be attracted to a company with a high-performing culture and those employees willing to extend the discretionary effort it takes to succeed in such as [*sic*] culture are more likely to be retained.

While some of the factors that affect financially-based performance measures, such as weather and economic conditions, are outside of the control of the Companies and its employees, many other factors, such as operating efficiency and spending are not. The financially-based measures in the Companies' incentive compensation plans are prudently designed and communicated to focus attention on those items that are controllable so that the best possible outcome can be achieved irrespective of uncontrollable factors. This is certainly better for customers rather than eliminating incentives for employees to control costs in favor of some other form of guaranteed compensation.

Well-designed incentive compensation plans, such as PSO's, that provide market competitive employee compensation (not "bonus" plans) do serve to balance customer, shareholder and employee welfare and has been realized as an appropriate and reasonable Company expense.

Furthermore, Virginia S.C.C. Case No. PUE 2011-00037 on behalf of Appalachian Power Company, provides precedent that certain incentive plans are reasonable, based on my testimony which is similar to that provided herein. The final order in this case states (p. 18):

APCo has established that 100% of these Incentive Plan costs should be approved. The Company has established that its total compensation costs - which include Incentive Plan costs - are reasonable for purposes of this proceeding. That is, the Company's total compensation package, including Incentive Plan compensation, 'results in compensation that is not higher than and is comparable to the market competitive level of compensation.' Indeed, as stated by APCo, the 'reasonableness of the Company's total compensation to employees is uncontroverted in this record.' We approve APCo's [AEP's Appalachian Power Company] Incentive Plan expenses as normalized by the Company.

In addition, we find that ratepayers should not bear Incentive Plan expenses that exceed a payout ratio of 100%, the benefits of which accrue to shareholders. See, e.g., Ex. 38 (Carr direct) at 50-51. We note, however, that APCo's normalized Incentive Plan expenses approximate such result and, thus, are approved herein. (Footnotes omitted.)

<u>Long Term Incentive Compensation</u>

Witness Farrar indicates that long-term incentive compensation is not necessary for the provision of utility services and may be detrimental to the interests of customers. I argue that the compensation opportunity and expense it represents is entirely necessary when the long-term compensation is provided as a component of (not a 'bonus,' in addition to) a market-competitive compensation package.

Witness Farrar also expresses the concern that long-term incentive compensation may encourage employees to pursue higher earnings and may be detrimental to the interest of customers, but he does not provide any evidence to show if or how the Companies long-term incentive plans are detrimental to customers. First, the Company is only seeking inclusion of the target value of long-term incentive compensation in its cost of service, so the cost of any above-target long-term incentive compensation payments would be born [*sic*] entirely by shareholders, not the customers. Witness D. Garrett provides the same rationales for eliminating long-term incentive compensation as he provided for annual incentive compensation.

I disagree with these rationales for the same reasons I have previously provided. D. Garrett also indicates that "The rationale behind the Commission's complete disallowance of long-term incentive portion of employee pay is that the "performance measures that result in the payment of long term incentive compensation are financial goals that benefit shareholders, rather than ratepayers." One of several substantial benefits that long-term incentive compensation provides to customers is minimizing employee turnover related expenses, such as hiring and training expenses. I've shown that the Companies' long-term incentive compensation is a critical component of a market-competitive total compensation package that enables the Company to attract and retain the employees it needs to efficiently and effectively provide its electric service to customers. It is not additional compensation on top of an already market-competitive compensation package. This point is undisputed. As such, the Company needs to provide this amount of compensation opportunity on average in order to compensate its employees market-competitively, irrespective of whether such compensation is provided in the form of long-term incentive compensation, base pay or some other form of compensation. Long-term incentive compensation provides a retention incentive that minimizes employee turnover related expenses without additional charges to the customer, beyond the cost of providing market-competitive compensation.

As shown in Exhibit ARC-D5 of my Direct Testimony (TCC vs. Market for Executive Positions, Compensation Survey Analysis-Executive Positions), the Companies' target total direct compensation (base salary, annual incentive compensation and long-term incentive compensation) is "3.4 percent above the target market on an aggregate total target direct compensation basis" for the 23 top executive positions included in the analysis. The amount of long-term incentive compensation included in this study is the target value, which is also the level that the Company is requesting be included in its cost of service. To demonstrate the importance of long-term incentive compensation as an essential component of providing market-competitive total compensation package for management employees, eliminating the long-term incentive portion would reduce employee pay to more than 45 percent below market-competitive levels. This illustrates that the long-term compensation opportunity that the Company provides is reasonable, customary and necessary to attract the employees the Company needs to operate its utility business efficiently and effectively.

OIEC's witness M. Garrett proposes to remove 50 percent of the Companies' short-term employee incentive compensation and 100 percent of the Companies' long-term employee 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 PSO assets. This would have a significant negative impact on the ability of PSO to earn a fair return on its assets going forward.

<u>Non-Qualified Post Retirement Benefits</u>

The Companies [*sic*] maintains non-qualified post-retirement benefits for its employees to provide benefits outside of the limits imposed on ERISA-qualified plans. AEP's non-qualified defined benefit plans also provide contractual benefits that were negotiated with respect to a few executives, nearly all of whom are now retired. No new contractual benefits have been negotiated in many years.

In my experience, most companies that provide qualified defined benefit pension plans to employees also provide non-qualified restoration plans that are similar to AEP's non-qualified pension plans. Such plans are a prevalent component of total rewards offered by large U.S. utility and industrial companies and are highly prevalent among companies with qualified defined benefit pension plans. The large PSO customers with incentive compensation plans that I previously mentioned utilize non-qualified defined benefit retirement plans. Witness Farrar states that this expense is unnecessary and expensive without offering any support for this position. Witness M. Garrett states that these costs are not necessary for the provision of utility service, but are instead discretionary costs of the shareholders designed to attract, retain and reward highly compensated employees. The Company needs employees with exceptional experience, knowledge, capabilities and skills to efficiently and effectively provide electric service to customers in all types of domestic and international conditions. Therefore, it is reasonable, prudent and in customers' interests for the Company to attract and retain such employees.

The Company, however, is not proposing that non-qualified defined benefit pension expense simply be presumed to be recoverable in rates. Instead, I respectfully recommend that the standard for including or excluding all compensation and benefit expense should be whether such costs are part of a market competitive total rewards package and whether such costs are otherwise reasonable and prudently incurred in the interests of customers. None of these benchmark points have been contested in this case with respect to non-qualified defined benefit pension expense.

Conclusion

The benefits derived from the Company's Annual Incentive Compensation Plan and Long-Term Incentive Plan create additional value for customers in that they have no additional cost to the customer above the ordinary cost of providing market competitive compensation to employees. Maintaining these incentive compensation programs also helps ensure that prior year cost savings are retained and prevents performance back-sliding, which is beneficial to customers.

The pay strategy of the Company's employee compensation plans successfully achieves the primary objective of providing reasonable, market-competitive compensation to employees. As such, the expense associated with the Companies' incentive plans is a necessary cost of providing electric service to customers. Therefore, I respectfully recommend that all such expense [*sic*] be included in the Company's cost of service as the Company proposed.

Summary of Rebuttal Testimony of 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 the purpose of his Rebuttal Testimony was to respond to Public Utility Division (PUD) of the Oklahoma Corporation Commission (OCC or Commission) Staff witness Kathy Champion's recommendation to discontinue PSO's System Reliability Rider (SRR or Rider), and include the costs and revenues for this activity in rate base to be recovered through base rates. Mr. Baker explained that there is no reasonable basis to discontinue a rider that has provided quantifiable customer reliability benefits since the SRR has been in place, and that the continuance of the SRR will help ensure these benefits continue.

Mr. Baker provided an overview of the SRR that has been in place since 2005, and discussed how the scope of the Rider has evolved over the years to include not only vegetation management, but to also allow for the recovery of undergrounding, system hardening, and grid resiliency activities. He also explained that the Commission found the current SRR in the public interest in Order No. 620006 issued January 7, 2014 (at page 2).

Mr. Baker testified that he does not support Ms. Champion's recommendation to eliminate the SRR and move the current Rider costs into base rates.

According to Mr. Baker, Ms. Champion takes no issue with the success that has resulted from the SRR with the substantial improvements in customer reliability. He discussed that she also failed to recognize the year-to-year variability of costs that occur, and gives no credit to the flexibility the Rider provides PSO in funding a variety of reliability programs. Rather, Ms. Champion would follow three criteria that are unlikely to be appropriate in all circumstances, without giving consideration to the broader benefits of the Rider.

Mr. Baker also testified to the flexibility provided by the SRR in terms of maintaining distribution system reliability and its benefit to PSO customers. According to Mr. Baker, the Company made tremendous gains in reliability improvements since the rider has been in place. Over the 10-year period of the Rider, the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), excluding major events, improved by 63.9% and 43.4%, respectively. PSO's vegetation management activities, along with its system hardening and grid resiliency activities, have contributed to shortened outage durations and reduced the impacts of severe weather events. The Rider also provides PSO the flexibility to manage expenses within the Rider cap that provides benefits to customers as year-to-year maintenance needs of the electric system change.

Mr. Baker also does not agree with Ms. Champion's assertion that riders do not provide utilities with incentive to be efficient as it applies to PSO, including the SRR. According to Mr. Baker, the Company has taken measures to manage SRR process improvement efficiencies throughout its vegetation management, system hardening and grid resiliency programs. Such efforts have resulted in reduced program costs along with the more efficient use of program resources.

As stated earlier, Mr. Baker does not support Ms. Champion's recommendation to recover SRR costs and revenues through base rates. According to Mr. Baker, as the Rider exists today, PSO's customers receive significant benefits from its reliability programs, while the Commission and the PUD receive cost and planning information on a quarterly basis to ensure that these costs are both reasonable and prudently incurred. Mr. Baker explained that the SRR has worked well for all parties since its inception, and there are no compelling reasons to eliminate it.

Mr. Baker also testified that the SRR is not just a 'tree rider'. He stated that Ms. Champion's focus on vegetation management gives no consideration to other reliability efforts such as system hardening and grid resiliency. Mr. Baker explained that Ms. Champion also does not account for the system hardening cap in her recommendation; an important component of the SRR. The Rider allows for the recovery of $7.7 million of depreciation, taxes, and carrying costs associated with system hardening and grid resiliency capital costs that would be lost with the elimination of the Rider. The elimination of recovery of these costs will make it more challenging for PSO to provide the capital required for system hardening and grid resiliency projects.

Mr. Baker concluded by testifying that given the success of the Rider program over the years, the Company supports continuing the existing Rider in its current form. The Rider will continue to protect customers due to the variability of program costs each year. Furthermore, it is consistent with the Final Order in Cause No. PUD 201300202 that supported PSO's need for flexibility. Mr. Baker testified that PSO has proven that it can effectively manage its vegetation management, system hardening and grid resiliency program costs, satisfy OCC requirements, and produce significant reliability benefits for our customers through the Rider. The current quarterly Rider review process has also provided considerable oversight and transparency of expenditures, planned work, and benefits.

<u>Summary of the Rebuttal Testimony of Steven L. Fate</u>

Mr. Fate's Rebuttal Testimony responded to certain analyses and positions taken by Mr. Scott Norwood on behalf of Oklahoma Industrial Energy Consumers (OIEC), and Messrs. Edwin C. Farrar, and Paul J. Wielgus on behalf of the Oklahoma Attorney General (AG). He explained why their analyses of PSO's Environmental Compliance Plan (ECP) are incomplete as compared to Public Service Company of Oklahoma's (PSO or Company), how their incomplete analyses lead to the wrong conclusions, and why PSO' [*sic*] analysis and ECP is prudent and results in costs to customers that are fair, just, and reasonable.

Responding to the OIEC, through its witness Mr. Norwood, whose Responsive Testimony focused heavily on the risk of reduced coal in PSO's energy supply mix without considering mitigating factors and the multitude of other risks PSO considered, Mr. Fate testified that when considering all risks and mitigating factors, the ECP is a reasonable, balanced approach to environmental compliance.

Mr. Norwood characterized PSO's ECP as "much more costly and risky" than retrofitting and continuing to operate both Northeastern coal units. Mr. Fate explained that contrary to Mr. Norwood's assessment, the ECP virtually eliminates the risk of future environmental regulations affecting coal units at a reasonable cost.

Mr. Fate testified that contrary to Mr. Norwood's position that carbon costs are highly speculative, including a cost of carbon in the analysis, is reasonable and a common practice in the energy industry. Evaluating the impact of future environmental regulations is reasonable and less speculative than excluding them from a long-range 30-year forecast.

Mr. Norwood criticized PSO for not evaluating the impact of the Clean Power Plan rule (CPP) on its economic evaluation of the ECP. However, Mr. Fate's Rebuttal Testimony points out that Mr. Norwood recently testified that it will be years before there will be any certainty as to how the rule impacts coal units since it depends on the yet to be determined compliance plans for the state of Oklahoma and the region.

Mr. Fate testified that direct comparisons drawn by Mr. Norwood between PSO's decision on Northeastern Units 3 & 4 and SWEPCO's Flint Creek Plant are not valid because of material differences in the fact situations between the plants. Flint Creek is uniquely situated and the analysis substantially different. Thus, the decisions regarding Flint Creek and Northeastern Units 3 & 4 are not directly comparable, and are both reasonable.

Mr. Fate described how Mr. Norwood overstated the percent difference in revenue requirement between compliance options, and that a more accurate picture of customers' rate impacts can be determined using the percent difference between total revenue requirements. When compared to total revenue requirement, the percent difference between scenarios is no more than 2.2 percent.

Mr. Fate further testified that Mr. Norwood incorrectly claimed PSO's analysis was deficient because the rate impact analysis was performed only on the first year. Contrary to Mr. Norwood's assertion, PSO considered a variety of rate impacts, including not only the year-one rate impact, but also the impact over the full 30-year planning period.

Mr. Norwood wrongly concluded PSO understated the ECP cost because it did not replace Northeastern Unit 4 generating capacity when retired in 2016. Mr. Fate testified that OIEC's position that PSO should have assumed nearly a full capacity replacement of Unit 4 is unreasonable, as it would have required PSO to predict a highly speculative future event. The unforeseeable load additions experienced subsequent to the decision to enter into the settlement agreement is a separate issue, and should not be factored into the cost or determination of prudence.

Mr. Norwood alleged that PSO's analysis was flawed because some of the scenarios assumed a 50-year service life for the coal-fired units in spite of evidence that a 60-year service life is possible. Mr. Fate testified that in fact, PSO's analysis is very reasonable and comprehensive because it evaluated both 50- and 60-year service lives, allowing for a better assess [*sic*] the risk of economic obsolescence of the coal-fired units in light of ongoing environmental compliance risks and make a more informed decision.

Mr. Norwood draws comparisons between Oklahoma Gas & Electric's (OG&E) and PSO's compliance plans to justify why he supports OG&E's plan and does not support PSO's plan. However, Mr. Fate points out in his Rebuttal Testimony that Mr. Norwood's comparison of the plans' attributes argues form over substance, and should be ignored.

Mr. Fate testified that contrary to Mr. Norwood [*sic*] allegation that PSO's decision to enter into the EPA Settlement was premature because of ongoing litigation of the Regional Haze Federal Implementation Plan (FIP) and Mercury and Air Toxics Standard (MATS), the timing of the Settlement Agreement provided a variety of benefits that ensured PSO could continue to fulfill its obligation to provide reliable electrical service at a reasonable cost.

The AG, through Witness Wielgus, recommended a disallowance of power purchased costs based on the omission in PSO's economic analysis of an assumed $2 million terminal value for a new natural gas-fired combined-cycle plant (NGCC). Mr. Fate testified that a $2 million terminal value of an NGCC is not material in the determination of prudence, and that a new NGCC plant was not a viable alternative, since there was insufficient time to construct a new unit.

Mr. Wielgus opined that PSO did not consider the risk associated with Power Purchase Agreements (PPA's), and he believes there is no guarantee the capacity will be available. Mr. Fate testified that all contractual agreements have some business risk. However, the PPA's include performance and availability guarantees along with liquidated damage provisions consistent with industry practices and provide substantial protection for customers.

Mr. Fate testified that AG Witness Farrar's unsubstantiated claim that PSO's analysis was not comprehensive was contrary to the AG's expert who examined PSO's ECP in Cause No. PUD 201200054, and found that PSO's analysis was comprehensive. Mr. Fate further testified that PSO's analysis included multiple scenarios and sensitivities, and therefore was complete and comprehensive evaluating five different compliance options and five different scenarios.

Mr. Fate summarized his Rebuttal Testimony by stating that the unfounded arguments made in the responsive testimonies of the AG and OIEC witnesses did not change the fact that PSO conducted a broad and thorough analysis of the compliance options and impacts on stakeholders, and chose a reasonable cost option that will provide customers benefits long into the future by avoiding environmental risk and cost.

<u>Summary of the Rebuttal Testimony of Thomas J. Meehan</u>

Mr. Thomas J. Meehan, who is employed by Sargent and Lundy, LLC (S&L), as Member, Senior Vice President, and Project Director, filed Rebuttal Testimony on behalf of PSO.

Mr. Meehan addressed and responded to statements made in the Responsive Testimony of Oklahoma Industrial Energy Consumers' (OIEC), Wal-Mart Stores East LP and Sam's East, Inc. witness Jacob Pous in regards to the Public Service Company of Oklahoma (PSO or Company) [*sic*] "Conceptual Demolition Cost Estimate" studies prepared by S&L. According to Mr. Meehan, Mr. Pous, without preparing his own comprehensive study, questions the methodologies and the assumptions employed in the studies prepared by S&L experts. Mr. Meehan stated that the criticisms of S&L's demolition cost studies are invalid and should be rejected as is further explained in his testimony.

It was Mr. Meehan's initial observation that to his knowledge, Mr. Pous had not prepared any independent studies of what costs would be expected to be incurred to dismantle and remove PSO's generating facilities upon their retirement. Mr. Meehan stated that Mr. Pous simply criticizes certain aspects of the S&L studies, without offering alternative engineering studies covering the complete costs of demolition of each of PSO's generating units based on consideration of the specific attributes of each facility.

The S&L studies he sponsored in his Direct Testimony are actual studies 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 testified that Mr. Pous' characterization that the S&L studies are "a worst case scenario that results in an excessively high-side demolition cost estimate" is incorrect. Mr. Meehan explained that the purpose of each study for each PSO generating plant was to arrive at safe and economical methods and processes to remove equipment, to demolish existing structures, and to remove other components such as concrete foundations and roadways, associated with a generating plant. Mr. Meehan testified that the cost estimates do not assume a "brick-by-brick and reverse engineering" approach to demolition and that in no case has S&L ever assumed a "brick-by-brick or reverse engineering demolition process" for an entire power plant in a demolition cost estimate study as quoted by Mr. Pous. Mr. Meehan stated that S&L collected plant-specific information and used plant general arrangement drawings with field reviews to estimate the scope of demolition necessary for each plant. Mr. Meehan explained that more detailed studies would be substantially more costly, and could not be obtained without bids specific to the work and that such detail would not measurably increase the accuracy of the estimates given the length of time until many of these plants retire.

Mr. Meehan disagreed with Mr. Pous' allegation that S&L failed to provide information and support for many critical components of its cost estimate. Mr. Meehan testified that while Mr. Pous consistently referenced data requests and information provided for past PSO base cases in his Responsive Testimony, he did not file requests for information in the current proceeding regarding the items he has decided are critical for support for the demolition cost studies. Further, S&L provided assumptions and specific details in the body of the demolition cost estimates in Exhibit TJM-3 at a level of detail sufficient for review by experienced and knowledgeable power plant engineers.

Mr. Meehan refuted Mr. Pous' allegation that the demolition cost estimates present a worst-case scenario for all demolition activities to be performed. Mr. Meehan explained that

S&L used reasonable and proper engineering and industry accepted practices to develop cost estimates with no bias for the costs being either high or low. Mr. Meehan described examples that clearly demonstrate that S&L's demolition cost estimates use cost-effective techniques for demolition of the subject facilities.

Mr. Meehan refuted Mr. Pous' criticism of S&L "not being in the business of actually dismantling power plants." Mr. Meehan explained that S&L could be thought of being similar to an architectural firm that designs and estimates the cost of a new building, but does not actually perform the construction. Whether the work is performed by S&L or subcontracted out, the knowledge, information, and experience is applicable to the demolition cost estimates.

Mr. Meehan addressed Mr. Pous' statement that S&L's assumption that equipment will have no other value than scrap value is unreasonable. Mr. Meehan explained that by the time the plant reaches the end of its useful life, the general condition of the plant has often degraded to a point where equipment has very little re-sale value other than scrap and that the remaining equipment 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. Meehan testified that Mr. Pous' example that compared a Nevada Power Company (NPC) demolition cost estimate prepared by Black & Veatch (B&V) (Docket 100-06003) to S&L's estimates was invalid. Mr. Meehan explained that the B&V demolition cost estimates in Docket 100-06003 (Docket 100-06003, page 50, line 2) refer directly back to the B&V demolition cost estimates, which were generated for NPC in Docket 05-10004. In Mr. Pous' testimony contained in Docket 05-10004 (page 24 lines 20 – 23 and footnotes), Mr. Pous states: "Based on a review of the Sargent & Lundy demolition cost estimates for Progress Energy, I found [B&V]'s cost estimates for NPC's units to be quite excessive." Mr. Meehan stated that it is inconceivable that Mr. Pous can say that the S&L demolition cost estimates are only a fraction of the B&V demolition cost estimates in Docket 05-10004 and then infer that S&L's demolition cost estimates equate to B&V demolition cost estimates in this proceeding.

Mr. Meehan testified that it would be improper to exclude an allowance for contingency from the demolition studies and that cost estimates for virtually all contract work includes some kind of contingency. It is a common and expected standard industry practice to include a positive contingency to account for unknowns and future changes not included in a cost estimate. The omission of a positive contingency in a cost estimate would be considered irresponsible and unreasonable.

Summary of the Rebuttal Testimony of David P. Sartin

David P. Sartin, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO or Company), testified on behalf of PSO.

According to Mr. Sartin, PSO was required to take action and to incur costs to comply with the United States Environmental Protection Agency's Regional Haze Rule and Mercury and Air Toxics Standard.

PSO has demonstrated that its environmental compliance plan (ECP) is a low cost, reasonable plan, among the plausible alternative plans.

Mr. Sartin further testified that compared to other environmental compliance alternatives, the ECP has the lowest customer rate impact for the first year rates are to be in effect, and is the lowest cost plan for at least the next 12 years. In fact, had PSO selected the full environmental retrofit of the Northeastern coal plant alternative seemingly advocated by others in this case, PSO's annual costs to comply would have been $75 million (85%) greater than the ECP, and this base rate case request would have been $75 million higher. The only independent evaluator in this case, employed by the Oklahoma Corporation Commission (OCC or Commission) Public Utility Division (PUD), found the ECP to be reasonable.

The ECP maintains PSO's fuel diversity, according to Mr. Sartin. PSO continues to have significant coal generation in its fuel mix for many years. The ECP provides the opportunity to further diversify PSO's energy supply mix by including cost effective renewable resources like wind and solar. The ECP permits this diversity without PSO investing $750 million in additional coal environmental controls that would be subject to the risk of future environmental regulations. As discussed above, it would have cost PSO customers an additional $75 million per year in this case to maintain fuel diversity using a historical view of diversity only considering coal and natural gas.

The OCC should not permit an intervener, representing a single set of customers, to supplant Company management's discretion for environmental compliance. PSO is responsible for ensuring electric service to all customers, and considering other important factors including employees, communities, and shareholders.

The Attorney General's opposition to the ECP is not supported by specific facts or any professional studies or analyses commissioned to review the ECP.

Since PSO's decision on the compliance plan, subsequent events have supported the decision.

- The Oklahoma State Implementation Plan (SIP) is enforceable under Oklahoma and federal laws.
- OG&E's litigation associated with the Regional Haze Rule is complete.
- PSO has added another 450 mega-watts of wind generation.
- The EPA has issued additional rules increasing the cost of coal generation, most notably the Clean Power Plan.
- The cost of PSO's ECP has declined due to lower costs of environmental control investment and replacement power.
- Natural gas prices can be expected to be moderate and stable for the foreseeable future due to the abundance of natural gas supply driven by shale development.

Mr. Sartin testified that PSO's proposed recovery of its Northeastern 3 and Comanche power plant environmental control costs either through a rider or base rates, beginning the first month after the environmental controls on Northeastern 3 are placed in service in early 2016, with deferred accounting to capture for future recovery or repayment the differences between the actual environmental costs and those collected in rates. Approval also is sought for recovery of environmental control consumables through the fuel clause. Purchased power expense would be recovered through fuel adjustment clause. The remaining costs of environmental controls on other PSO generating units would occur through base rates, and there were no major concerns from other parties regarding their cost recovery.

The ECP cost recovery sought by PSO is reasonable because it does not begin until the new environmental controls are complete and in service. Recovery of the costs would occur over time periods that reflect the remaining lives of generation assets, which will not penalize future customers.

With PSO's proposed cost recovery of environmental controls, there is no shifting of risk between PSO and customers because the OCC retains its authority to review the investments for prudence prior to including them in rate base.

Mr. Sartin also testified that contrary to views of some parties regarding post test year adjustments and riders to recover the ECP, the Commission has the authority to approve PSO's requested cost recovery. There are no valid reasons to delay approval of cost recovery to yet another base rate case.

PSO's proposed capital structure is reasonable because it is consistent with comparable utilities' structures, and consistent with positions taken by the PUD and the OCC in prior PSO and other OCC jurisdictional utility cases. PSO took the opportunity to issue $250 million of debt at attractive interest rates early in 2015 by recognizing the favorable interest rate environment that existed at that time, and by recognizing and avoiding market risks associated with waiting until later in the year. While PSO could have waited until later in the year and avoided the impacts the new debt would temporarily have on its capital structure for rate case purposes, PSO did the right thing for customers and issued debt when it believed the market would provide low interest rates.

PSO's requested 10.5% return on equity is reasonable, according to Mr. Sartin because it is based on a variety of factors, including conditions in capital markets and certain risks faced by PSO. Other parties' recommended returns are lower than those recently awarded by other utility commissions, and some rely too heavily on a single model. Adjustments to return on equity to reflect the effect of riders are not appropriate since the risk of riders is included in the determination of returns.

Since there is no problem with the OCC's current practice of considering and approving riders, there is no reason to adopt prescriptive standards for the approval of riders.

PSO's proposed rate increase has been reduced by $3 million compared to Direct Testimony, largely due to updating rate base to actual amounts six-months post test year. PSO has addressed all of the other parties' proposed adjustments to its recovery of costs in Rebuttal Testimony, and continues to believe the request for rate relief is reasonable and should be approved by the Commission.

PSO's rates will increase due to the costs to comply with the environmental regulations, and this situation is not unique to PSO as utilities across the country either have or will face increasing costs to comply with new regulations. Under PSO's full rate request in this case, including the ECP, PSO's total average electric costs will remain competitive even after prices increase from this application, as they are expected to be 2% below the state of Oklahoma average, 6% below the regional average, and 22% below the national average.

Summary of the Rebuttal Testimony of C. Richard Ross

Mr. Ross filed Rebuttal Testimony to address certain inappropriate conclusions reached by Oklahoma Corporation Commission Public Utility Division (PUD) witnesses Mr. Chaplin and Ms. Champion regarding Public Service Company of Oklahoma's (PSO) ability to accurately predict and control Southwest Power Pool (SPP) transmission expenses.

Mr. Ross testified that despite the claims by Mr. Chaplin that the SPP charges are not totally unpredictable, and by Ms. Champion that the SPP Transmission Cost Rider does not meet the controllable cost criterion and the unpredictability criterion proposed by the PUD, the recent history of the SPP charges, and the large number of variables impacting them clearly make them extremely difficult to predict with any reasonable accuracy. SPP's cost monitoring process itself, allowing for a +/-20% variance, recognizes there are a wide variety of issues that can impact the final cost of a particular transmission project and make them, to some significant degree, unpredictable. More importantly, a project's in-service-date is a critical factor impacting when the construction costs are actually incorporated into the transmission owner's rates and SPP's transmission rates. A SPP member might predict the cost of a project perfectly, but miss the expected in-service-date so that the project's cost is not included in the transmission owner's rates update for the expected year. Such a situation could lead to an error in PSO's predicted transmission expense attributable to a project for the year of as much as +/-100%. Such levels of uncertainty are clearly unpredictable and cannot be controlled by participation in the SPP process.

Mr. Chaplin's also asserts that by not allowing PSO to defer that difference [in actual SPP expenses and the amount included in PSO's base rates], this incentivizes PSO to continually pursue cost control within the SPP organizational structure. Mr. Ross testified AEP's participation did not control costs. According to Mr. Ross, AEP makes every effort to ensure that PSO customers do not bear unreasonable SPP-related costs. Suggesting that these efforts would be bolstered by PSO's continued inability to defer these expenses, or conversely, to suggest that PSO would somehow reduce this participation and advocacy within SPP due to the approval of deferral accounting, is inconsistent with the Company's historical actions and future intentions.

Summary of the Prepared Rebuttal Testimony of Richard G. Smead

Richard G. Smead of the firm RBN, Energy LLC submitted Rebuttal Testimony on behalf of PSO. Mr. Smead addressed those portions of the Responsive Testimony of Scott A. Norwood and Dr. Craig Roach (Mr. Norwood who testified on behalf of the Oklahoma Industrial Energy Consumers and Dr. Roach on behalf of the Staff of the Oklahoma Corporation Commission), to the extent such testimony was relevant to the natural gas supply and pricing issues addressed by Mr. Smead in his Direct Testimony. Specifically, Mr. Smead rebutted Mr. Norwood's various allegations that PSO's commitment to natural gas fired generation as the Northeastern coal units are ramped down and retired in compliance with PSO's EPA settlement would create higher energy costs than estimated by PSO, and would involve significant price risk for consumers. Mr. Smead further reviewed Dr. Roach's analysis which, while it endorsed PSO's approach, expressed concern over upward pressure on natural gas prices.

With respect to Mr. Norwood's Responsive Testimony, Mr. Smead concluded that the price forecast comparisons employed by Mr. Norwood were stale and inaccurate, having already been superseded by lower price estimates at the time of Mr. Norwood's testimony in Cause No. PUD 201100054 (the "54 Case"), from which Mr. Norwood apparently drew all of his work on the subject without any updates. Mr. Smead determined that Mr. Norwood's review of PSO's range of natural gas price forecasts that underlie PSO's economic analysis of the EPA settlement is deeply flawed and should be disregarded. If anything, Mr. Smead concluded, the Energy Information Administration (EIA) annual energy outlook for 2012 (AEO2012) used by Mr. Norwood was superseded by AEO2013 well before the submission of testimony in the 54 Case. Based on Mr. Norwood's approach to evaluating the sensitivity of the economic impact of the EPA settlement to variations in natural gas cost from PSO's estimate, Mr. Smead determined that the use of the correct year's EIA estimate would have shown incremental savings from the use of natural gas of over $300 million on both a nominal and a net present value basis, through Mr. Norwood's planning horizon of 2040. Mr. Smead also showed that if EIA's 'high-resource" cases from the 2012, 2013 (available during the 54 Case), and most recent 2015 annual energy outlook, which are remarkably consistent with each other and increasingly likely based on the behavior of actual production and pricing, could yield costs as much as nearly $3 billion below PSO's estimate, with a net present value of $1 billion worth of savings.

In reviewing Dr. Roach's testimony, Mr. Smead acknowledged and strongly agreed with Dr. Roach's conclusion that PSO's natural gas price estimates were a reasonable basis for the evaluation of the EPA settlement. Mr. Smead further agreed with Dr. Roach that it was legitimate to recognize and evaluate concerns over price volatility or that the regulation of natural gas drilling operations to address issues around development impact or methane emissions could cause chronic increases in prices, but Mr. Smead explained why he disagreed with Dr. Roach as to the potential significance of those factors. Mr. Smead's explanation was based, in concert with his Direct Testimony, on the fundamentals of the shale revolution, on the work of an important multi-sector task force on price stability whose 2011 report indicated multiple reasons volatility was a thing of the past, and on the massive, ongoing increases in drilling productivity in the natural gas industry, which offset any impact from increased costs. Mr. Smead further explained that a likely pattern in the future, similar to the experience of 2012-2013, is some downward volatility, wherein prices drop because of mild weather, with recovery to the expected prices, but then with constraints on further upward movement because of the industry's ability to respond with additional supply.

Summary of the Rebuttal Testimony of Robert B. Hevert

Company Witness Robert B. Hevert's Rebuttal Testimony addresses the Responsive Testimonies of Mr. David J. Garrett on behalf of the Public Utility Division (PUD) of the Oklahoma Corporation Commission (Staff); Mr. J. Bertram Solomon on behalf of the Oklahoma Attorney General (OAG); Ms. Maureen L. Reno and Dr. Larry Blank on behalf of The United States Department of Defense and All Other Federal Executive Agencies (DOD); Mr. David C. Parcell on behalf of Oklahoma Industrial Energy Consumers (OIEC); and Mr. Steve W. Chriss on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc. (Wal-Mart) (the Opposing ROE Witnesses) as their testimony relates the Company's Return on Equity (ROE) and capital structure. Mr. Hevert's Rebuttal Testimony includes a set of updated analyses supporting his Cost of Equity recommendation; those analyses demonstrate that his recommended range of

10.25 percent to 10.75 percent, and his specific recommendation of 10.50 percent, remain reasonable and appropriate.

Mr. Hevert's Rebuttal Testimony explains that none of the arguments provided by the Opposing ROE Witnesses have caused him to change his recommendations regarding the Company's ROE and capital structure. The fact that the Opposing ROE Witnesses' recommendations are similar in measure does not mean that their analytical approaches are appropriate, or that their recommendations are reasonable. Regardless of the analytical approach taken, the Opposing ROE Witnesses' recommendations fall far below observable measures of reasonableness, such as the returns available to other utility companies. Mr. Hevert notes that the highest of the Opposing ROE Witnesses' recommendations, 9.30 percent, falls below 97.00 percent of the returns authorized for vertically integrated electric utilities from January 2012 through October 2015.

Although there are specific reasons why their individual recommendations are unduly low, there also are factors that commonly reduce the Opposing ROE Witnesses' analytical results. For example, certain of the Opposing ROE Witnesses base their analyses on proxy companies that are fundamentally incomparable to PSO, or that conflict with their own screening criteria. As a result, the fundamental bases of their analyses, conclusions, and recommendations are questionable. More commonly, in applying their Discounted Cash Flow models, the Opposing ROE Witnesses rely on growth rates that are inappropriately low, or that are constrained by what they may consider to be "sustainable" or "fundamental" levels of long-term growth. Similarly, the Opposing ROE Witnesses' Capital Asset Pricing Model analyses rely on inputs that are incompatible with long-term experience, or cannot be supported by expected market and economic conditions. Mr. Hevert's Rebuttal Testimony also explains that although the Opposing ROE Witnesses may point to the level of interest rates to support their ROE recommendations, they do not recognize that the two do not change on a one-to-one basis. Consequently, their recommendations are low in the context of prevailing interest rates; they are lower still considering expected increasing interest rates going forward.

As to the Company's requested capital structure, which includes 48.00 percent common equity and 52.00 percent long-term debt, Mr. Hevert explains that while reasonable, it does contain more debt leverage than similarly situated electric utilities. Certain of the Opposing ROE Witnesses recommend capital structures with even higher levels of debt, arguing that a debt ratio as high as 65.00 percent is "optimal." Mr. Hevert demonstrates that the analyses underlying those conclusions are deeply flawed, and that reducing the equity ratio below the Company's recommendation would have the counter-productive effect of increasing its risk and, therefore, its overall Cost of Capital.

Lastly, Mr. Hevert's Rebuttal Testimony explains that moving the undepreciated balance of Northeastern Station Unit 4 to a regulatory asset does not so mitigate risk that the return on that balance should be reduced to the cost of debt. Investors do not view such assets as distinguishable from the remainder of the balance sheet, nor do they see regulatory assets as removing regulatory risk. Consequently, it is the overall rate of return, not the cost of debt, that should be applied to the undepreciated balance.

<u>Summary of the Rebuttal Testimony of Randall W. Hamlett</u>

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 of Public Service Company of Oklahoma (PSO or Company).

Mr. Hamlett's Rebuttal Testimony responded to recommendations by other parties to this case associated with PSO's recovery of the Northeastern coal plant costs, PSO's environmental cost recovery plan and PSO's base rate revenue requirement.

According to Mr. Hamlett, PSO filed a traditional base rate case on all issues except one, PSO's environmental compliance cost recovery plan. PSO's environmental compliance cost recovery plan provides cost recovery that matches the date new environmental controls are placed in service and providing service to customers for Northeastern Unit 3 and provides for deferred accounting so customers pay PSO's actual costs for the environmental controls for both Northeastern Unit 3 and Comanche. This complies with the Commission's finding in Cause No. PUD 200800144, Order No. 564437 that states the concept behind known and measurable is to have rates based upon the levels of expenses, revenues and rate base that will most likely be reflective of the expenses and revenue during the time rates are in effect. Had PSO chosen to retrofit both coal units, PSO's rate increase would be higher by almost $75 million in this case.

Mr. Hamlett testified that PSO's request for recovery of Northeastern Unit [*sic*] 3 and 4 existing plant costs is reasonable and will not result in the creation of regulatory assets if approved by the Commission. Certain other parties make recommendations that do not comply with the standard accounting retirement entries under the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). Some of their recommendations would result in regulatory asset accounting (e.g. recovery through 2040 versus 2026) which PSO can implement but is not as reasonable as PSO's proposal. PSO's proposal does not result in an over-recovery of Northeastern Unit 4 costs. Contrary to certain parties' positions, under standard FERC USOA accounting for retirements, the cost of Northeastern Unit 3 and 4 assets remain on PSO's books as net plant in service and should continue to be included in rate base with the full rate of return granted by the OCC in this case.

Mr. Hamlett provided six-month updates for various rate base items. PSO's pension prepayment has resulted in pension expense savings and should be included in rate base as recommended by PSO and PUD Staff. This prepayment does not reflect what could be considered discretionary contributions, other than $4.4 million made in 2014. The Commission did not accept Mr. Mark Garrett's recommendation to disallow capitalized incentives in Cause No. PUD 200800144 and should reject his recommendation again in this proceeding. PUD witness Thompson is the only witness that appropriately included the Non-AMI meter regulatory asset in rate base and amortization expense in compliance with the Commission's order in Cause No. PUD 201300217.

According to Mr. Hamlett, payroll updated to the annualized amount as of July 31, 2015, is reasonable and should be included in cost of service. The recommendation of PUD for ad valorem taxes results in a value that is mainly based upon January 1, 2014, plant values that are outdated since rates will be implemented in 2016 and will result in the Company under recovering this expense. Mr. Hamlett provided updated ad valorem tax expense synchronized to the July 31, 2015, updated investment levels which is similar to the recommendations of the AG and DOD and is much more reasonable to include in developing rates to be implemented in 2016.

Mr. Hamlett testified that depreciation expense will need to be annualized using the final depreciation rates approved by the Commission. Rate case expense should be amortized over two years consistent with the two orders issued in this case and should include the amount of fees related to the PUD and AG expert witnesses in compliance with those same two orders. Consumables should be included in fuel as recommended by the PUD. Finally, Mr. Hamlett has proposed that over/under accounting for Southwest Power Pool (SPP) expenses that are not recovered through the rider should be adopted. In Cause No. PUD 200800144, PUD recommended over/under accounting of storm costs because storms are unpredictable and outside the control of PSO and this accounting is reasonable and fair to the utility and consumers. The SPP costs are also both unpredictable and outside of PSO's control as detailed in the Rebuttal Testimony of Mr. Ross. As such, Mr. Hamlett's proposal should be adopted by the Commission as it is reasonable and fair to the utility and consumers.

Mr. Hamlett recalculated PSO's base rate revenue requirement (EXHIBIT RWH-7R) which shows a net revenue deficiency of $80.7 million before rate design issues.

<u>Summary of the Rebuttal Testimony of John O. Aaron</u>

John O. Aaron, Manager, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), provided Rebuttal Testimony on behalf of Public Service Company of Oklahoma (PSO or Company). Mr. Aaron's Rebuttal Testimony addressed recommendations made by various parties in the area of PSO's cost-of-service study and PSO's proposed Environmental Compliance Rider (ECR). He responded to recommendations by the following witnesses:

- Oklahoma Corporation Commission (OCC) Public Utility Division (PUD) witness Jeremy Schwartz regarding an updated Minimum System study;
- United States Department of Defense and all Other Federal Executive Agencies (DoD/FEA) witness Dr. Larry Blank regarding modifications to PSO's Environmental Compliance Rider;
- Oklahoma Attorney General (AG) witness James Daniels regarding the ECR tariff and its calculations;
- Oklahoma Industrial Energy Consumers (OIEC) witness Mark Garrett regarding PSO's transmission cost allocations;
- Oklahoma Industrial Energy Consumers (OIEC) witness Scott Norwood regarding purchased power energy cost allocations;
- United States Department of Defense and all Other Federal Executive Agencies (DoD/FEA) witness Lafayette Morgan regarding revenue normalization and customer growth; and,
- Oklahoma Attorney General (AG) witness Ed Farrar regarding revenue normalization and customer growth.

In response to Mr. Schwartz's recommendation, Mr. Aaron testified that a Minimum System study attempts to classify distribution system plant investments between a customer component and a demand component since distribution plant is placed in service to provide service to a customer and to meet a customer's demand. As discussed in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (pages 90-92), one method of determining this customer and demand classification is a "minimum-size-of-facilities method" or Minimum System study. This method determines the minimum size for investments recorded in FERC Accounts 364 to 369 and classifies this amount as the customer component. The remaining difference between the total investment recorded in these accounts and the customer component is classified as the demand component.

Minimum system studies can produce widely varying results depending on the assumptions used and may not result in a more accurate classification of costs. The NARUC manual notes (page 95) the following:

- The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

- Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some costs [*sic*] analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

PSO classified the distribution assets recorded in the following FERC Accounts 364 - 368 as demand related consistent with the Final Order in Cause No. PUD 200800144, wherein the Commission found PSO's demand-only classification reasonable. In that cause, PSO's filed testimony stated that PSO's distribution system is sized to meet the maximum instantaneous loads placed on it – which is directly related to demands and not how customers are connected. The distribution system includes poles, wires, and conduit sized to meet the maximum local demand imposed on the system. The costs of those facilities does not vary directly with the number of customers, unlike certain distribution costs such as service drops (Account 369) and meters (Account 370), which are allocated on the basis of customers.

Although PSO believes that the demand classification is appropriate for the specified FERC Accounts 364 to 368, it recognizes it is equally important to provide the PUD with information it believes necessary to adequately assess PSO's base service charges. An updated Minimum System study will not change the fact that the distribution costs at issue are fixed. Rather than require any future change in PSO's base service charge to be based solely on the results of the Minimum System study, PSO will provide detailed explanations and company specific methods supporting any change in its base service charges.

Regarding the ECR issues identified by Dr. Blank and Mr. Daniel, Mr. Aaron provided changes to the ECR language (EXHIBIT JOA-1R) and factors (EXHIBIT JOA-2R) to address these issues. Additionally, Mr. Aaron provided an additional ECR tariff (EXHIBIT JOA-3R) in response to Dr. Blank's alternative rate recovery for Northeastern Unit 4.

Mr. Aaron addressed OIEC witness Garrett's recommendation to use a four coincident peak (4CP) allocation for transmission costs to retail customers rather than PSO's proposed twelve coincident peak (12CP) allocation.

Mr. Aaron testified that the 12CP transmission allocation appropriately allocates transmission costs to the class responsible for that cost utilizing the same methodology by which PSO is billed for transmission costs in the SPP and thus reflects "how retail customers actually use the transmission system." The SPP bills PSO for transmission services on a 12CP basis as mandated by the SPP OATT. PSO's requested 12CP transmission allocation is consistent with cost recovery and rate principles whereby rates are designed to recover the costs incurred to serve each respective class. Mr. Aaron notes that Dr. Blank recommends adoption of PSO's allocation methods and results. Dr. Blank stated that the production, transmission, distribution and customer allocations are "all logically applied, cost-based allocation approaches...commonly used in other jurisdictions."

Mr. Aaron addressed OIEC witness Norwood's recommendation to apply a demand allocator to all purchased power energy costs resulting from the retirement of PSO's Northeastern coal units.

Mr. Aaron testified that it is a well-established cost causation principle that capacity (demand) charges representing the cost of generation plant assets are allocated on a production demand allocator and energy charges are allocated on a production energy allocator. The purchased power costs incurred by PSO to replace the output of the retired Northeastern coal units will include a capacity (demand) component and an energy component (including fuel). Mr. Aaron noted that Mr. Garrett on behalf of OIEC supported this principle when testifying in Cause No. PUD 200900031, an application by PSO to recover costs incurred from two wind power contracts through the fuel adjustment clause. In his Responsive Testimony in that cause, Mr. Garrett testified that the cost of coal plants and gas plants used to produce power are allocated on a demand basis and the cost of fuel is allocated on an energy basis.

Mr. Norwood supported his claim be [*sic*] referencing PSO's fuel cost adjustment rider for the recovery of certain costs of wind energy purchased contracts and gas transportation costs. The purchase power contracts described in this proceeding are conventional purchase arrangements with distinct demand (capacity) and energy (including fuel) components and are not similar to PSO's wind energy purchase contracts. Unlike PSO's wind energy purchase contracts, demand and energy costs are associated with the purchase contracts described in this proceeding. Regarding the gas transportation costs, Mr. Norwood attempts to draw similarities between the conventional purchase arrangements described in this proceeding with cost recoveries that are not the same. The gas transportation costs allocated on a demand basis for recovery through PSO's fuel adjustment clause reflects the treatment as if PSO owned the gas transportation system. The cost of gas, excluding the transportation component, continued to be allocated on an energy basis.

PSO has allocated the costs of these conventional type purchase arrangements following traditional cost allocation methodologies – demand (capacity) costs allocated on demand and energy costs allocated on energy. These conventional purchase contracts are not similar to the wind energy contract or the gas transportation agreement cost recoveries described by Mr. Norwood.

Mr. Aaron addressed DoD/FEA witness Morgan's and AG witness Farrar's adjustment to increase revenues to reflect updated customer counts as of July 31, 2015, the six month post-test year period.

Mr. Aaron testified that PSO's test-year adjusted annualized base rate revenues are the result of a comprehensive analysis reflecting the test-year ending level of customers, weather adjustments, rate changes, and other specific customer billing adjustments. The adjustments recommended by Mr. Morgan and Mr. Farrar reflect only the growth in customers that occurred in the six month post-test year period to derive their change in revenues. Cause No. PUD 200800144, Order No. 564437, states (pages 3-4) that "adjustments to expenses and revenues, which fluctuate based upon the number of customers, the weather, the time of year, etc. should be closely reviewed to make certain the normalization methodology captures the best possible estimate of future expenses and revenues. The Commission finds that simply "updating" expenses and revenues to the six-month post-test year period, without an analysis regarding the reasons for the change since test year-end, has the potential for creating a new test year that has incomplete and/or mismatched information within it." A proper adjustment to annualize the revenues that occurred in the six month post-test year period would also consider weather adjustments, rate changes, and other specific customer billing adjustments. Mr. Morgan and Mr. Farrar only reviewed one component, the number of customers.

<u>Summary of Rebuttal Testimony of John J. Spanos</u>

John J. Spanos with the firm of Gannett Fleming Valuation and Rate Consultants, LLC testified on behalf of Public Service Company of Oklahoma (PSO or Company).

Mr. Spanos sponsored the depreciation study performed for Public Service Company of Oklahoma. The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2014. The proposed rates appropriately reflect the rates at which PSO's assets should be depreciated over their useful lives and are based on the most commonly used methods and procedures for determining depreciation rates.

In Rebuttal Testimony Mr. Spanos stated he was responding to the direct testimonies filed by Public Utility Division (PUD) witnesses David Garrett and Craig Roach; Oklahoma Industrial Energy Consumers (OIEC), Wal-Mart Stores, LP and Sam's East, Inc. OIEC witnesses

Jacob Pous and Mark Garrett; Attorney General witness E. Cary Cook; and United States Department of Defense (DOD) witness Larry Black [*sic*] on depreciation related issues.

The first part of Mr. Spanos' testimony presents a general discussion of the depreciation study process. He discusses both the objective of depreciation in allocating the full costs of the Company's assets (original cost less net salvage) over their service lives, and the process and judgments involved in estimating service lives and net salvage. Mr. Spanos explains in detail, the depreciation study and the evidence supporting it are consistent with depreciation studies conducted across the country and the study is consistent with accepted practices in the industry.

Each witness's proposal regarding Northeast Units 3 and 4 do not meet the objectives of depreciation of allocating costs over the service lives of the plant, and instead defer costs to future customers who will not receive any service from the plant. OIEC and PUD's proposals for mass property service lives do not correctly interpret the historical data and do not utilize the proper judgment in estimating service lives, and as a result forecast service lives for the Company's assets that are far too long for the types of property studied. Mr. Pous' net salvage analyses similarly results in net salvage estimates that will recover far less than the full cost of the Company's assets for many accounts.

After the general section, Mr. Spanos addresses in more detail the specific adjustments and criticisms to the depreciation study that each witness proposes. These include:

- Northeast Units 3 and 4. The Company plans to retire Northeast Unit 4 in 2016 and Unit 3 in 2026. The current depreciation rates are based on an estimated retirement date for these units of 2040, which was originally proposed by OIEC and the AG in Cause No. 200600285. Despite the fact that the Company will retire these units earlier than 2040, PUD, OIEC, the AG and DOD propose to depreciate the costs of these units through 2040. That is, they propose to depreciate the costs of these units over a period of time longer than their actual service lives. Their proposals, therefore, do not meet the objective of depreciation of allocating the costs of assets over their service life, and instead will produce intergenerational inequity by causing future customers to pay the costs of plants from which they will not be receiving service.

- Terminal net salvage for production plant accounts. In this section, Mr. Spanos explained that net salvage estimates must be stated at the cost at which they will be incurred, and that it is therefore appropriate to escalate these costs to the year of the expected retirement of each facility. The approach in the depreciation study of escalating these costs is consistent with depreciation principles accepted and supported by the vast majority of jurisdictions and in authoritative depreciation texts. This approach is also consistent with depreciation principles Mr. Pous supports in his testimony and is consistent with net salvage estimates he has made for other plant accounts. Mr. Spanos also addresses Mr. Pous' claims regarding the value of the sites for the Company's plants. Mr. Spanos did not address the decommissioning study in detail, as that was addressed in Mr. Meehan's Rebuttal Testimony.

- Interim survivor curves for production plant accounts. The methodology for interim retirements that Mr. Spanos used in the depreciation study is widely accepted in the industry, is appropriate for this proceeding and is not a new method as characterized by Mr. Pous. It is in fact a method that is more precise than the approximation that Mr. Pous' [*sic*] has proposed. Mr. Pous' method, in contrast, produces unusual and unrealistic results and is not reflective of the service life expectations of the assets in the production plant accounts. Further, Mr. Pous has not even updated the interim retirement rates to be consistent with the Company's actual experience. PUD has used the same method for interim retirements as Mr. Spanos, but has selected interim survivor curves for some accounts that are not as reflective of the property studied.

- Mass property life analysis. Both PUD and OIEC have recommended different service life estimates for certain mass property accounts. PUD has estimated the changes to the largest number of accounts, and since PUD's estimates are inappropriately based solely on mathematical curve matching, Mr. Garrett's estimates are unreasonable and unrealistic for the property studied. OIEC has only recommended adjustments to the service life estimates Mr. Spanos made for four accounts. As Mr. Spanos explained, Mr. Pous' estimates are not as reasonable forecasts of future service life characteristics as my estimates.

- Mass property and interim net salvage. PUD has not recommended any changes to the Company's estimates. Mr. Pous has recommended adjustments to the net salvage estimates for four transmission plant accounts, one general plant account, and for the interim net salvage estimates for steam production and other production accounts. As Mr. Spanos explained, in making his estimates, Mr. Pous chooses to ignore the Company's actual experience and propose [*sic*] estimates that deviate significantly from the historical data. Strangely, Mr. Pous is also critical of Mr. Spanos' study for doing the type of analyses he had argued was necessary in the Company's previous study. Mr. Pous' recommendations are for net salvage estimates that are far below the Company's actual experience, and as a result, his analysis produces estimates that are far less negative than appropriate.

Summary of the Rebuttal Testimony of Mark A. Becker

Mr. Becker's Rebuttal Testimony responds to certain errors and arguments made by Oklahoma Industrial Energy Consumers (OIEC) witness Scott Norwood. In particular, Mr. Becker rebuts Mr. Norwood's misleading representation of the results associated with the Company's Strategist® based economic analysis of Public Service Company of Oklahoma's (PSO or Company) environmental compliance plan alternatives and his belief that PSO's economic analysis was flawed. In rebutting Mr. Norwood's arguments, Mr. Becker also responds to similar arguments made by Mr. Edwin Farrar, who is a witness for the Office of the Attorney General of Oklahoma.

Mr. Norwood offers discussion and tables summarizing his analysis of the relative long-term economics associated with the Company's Strategist modeling. Mr. Becker has two primary issues with Mr. Norwood's representations of the modeled results. First, Mr. Norwood provides dollar amounts in both net present value, and in nominal value. Any valid cost comparison between environmental compliance alternatives cannot be properly presented or evaluated by simply adding the nominal dollar differences between those long-term plans over the 2011 through 2040 period. Rather, the long-accepted and correct approach is one that reflects those relative economics in discounted or present-valued dollars. All of Mr. Norwood's nominal dollar representations should be ignored because standard business decision-making is based on present value amounts. Second, Mr. Norwood errs by suggesting that performing a simple-averaging of the results across various commodity price scenarios and assumptions for Northeastern retrofit expected life and recovery periods provides information that could be used in the determination of the reasonableness of PSO's environmental compliance plan. The use of a simple averaging technique is flawed. Mr. Becker and the Company believes [*sic*] the most relevant information is contained in the "Base" forecast scenarios, rather than the alternative scenarios, because the Base forecast contains those assumptions the Company believes are more likely to occur. It is Mr. Becker and the Company's belief that a higher probability exists that the ultimate life of a Coal Retrofit solution would be 15 years as opposed to 25 years, which is why it is considered as a base assumption. The Low Band (Low Fuel) and High Band (High Fuel) commodity pricing are less likely to occur than the Base commodity-pricing scenario. Simply averaging the results of those less probable commodity price scenarios with the Base commodity price scenario suggests that they should have equal weighting, but they so [*sic*] not, and these comparisons should be dismissed.

In addition, Mr. Norwood simply removes the cost of CO2 emissions from the analysis results without considering the correlative impact on other commodity prices (gas, coal, SPP Market energy) that CO2 pricing causes. In other words, one cannot simply remove CO2 pricing impacts without reflecting the direct and indirect impacts such a change would have on other commodity prices.

Mr. Norwood also contends that PSO used an extremely low peak demand forecast in its EPA Settlement analysis which would mitigate the need for replacement capacity. Mr. Norwood's contention is based on incorrectly comparing peak demand forecasts that have not been adjusted for effects that weather has on PSO's actual peak demand each year.

Summary of the Rebuttal Testimony of 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 Public Service Company of Oklahoma (PSO).

Mr. Frantz is responsible for maintaining the accounting books and records, and regulatory reporting for AEPSC. He is also responsible for AEPSC's monthly service billings to its affiliates. His responsibilities for AEPSC also include compliance with the Federal Energy Regulatory Commission's Uniform System of Accounts accounting and reporting requirements.

Mr. Frantz' Rebuttal Testimony rebuts the adjustments to AEPSC test year affiliate charges to PSO presented in the Responsive Testimony of Oklahoma Attorney General (AG) witness Paul J. Wielgus. Mr. Frantz also rebuts the calculation of the disallowance of

Supplemental Executive Retirement Plan (SERP) expense presented in the Responsive Testimony of Oklahoma Industrial Energy Consumers (OIEC) witness Mark E. Garrett.

According to Mr. Frantz, AG witness Wielgus recommends the removal of approximately $2.9 million of the AEPSC costs charged to PSO, which is the increase in total costs billed from AEPSC to PSO in this Cause when compared to Cause No. PUD 201300217. OIEC witness Garrett recommends a reduction of $600,209 related to SERP expense included in PSO's filing.

Mr. Frantz testified that PSO provided, in his Direct Testimony, an explanation for the increase in AEPSC costs billed to PSO in this Cause when compared to Cause No. PUD 201300217. According to Mr. Frantz, Mr. Wielgus completely ignores all of the evidence provided by PSO in support of these costs. Mr. Wielgus ignores the actual facts surrounding PSO's incurrence of affiliate charges. Mr. Wielgus ignores the Oklahoma Corporation Commission (OCC) rules which exempt corporate and shared costs from the Commission's rules requiring asymmetrical pricing for affiliate transactions to the extent such costs are: (1) included in a general rate case and provided as part of the general filing package required under Chapter 70 of the OCC rules or, (2) are provided in response to a specific OCC request. PSO has met these requirements. It is also notable that the Commission has, by historically approving PSO shared services charges without adjustment and enacting a rule exempting shared services charges from the asymmetrical pricing rules, shown its recognition of the benefits and protections inherent in the system by which AEPSC provides shared services and bills PSO. For example, in Final Order No. 564437, Cause No. PUD 200800144, the Commission found that "PSO provided support for the affiliate costs paid by PSO and that no adjustment to these expenses is necessary.

According to Mr. Frantz, OIEC witness Garrett's calculation of SERP expense included in PSO's filing was flawed because he started with the incorrect amount of AEPSC SERP costs requested by PSO, and he excluded the PSO Payroll Cost-of Service (COS) ratio to allocate the adjustment between COS and non-COS account. Please see EXHIBIT BJF-1R for the correct calculation.

<u>Summary of the Rebuttal Testimony of Gary C. Knight</u>

Mr. Gary C. Knight, who is employed by the Public Service Company of Oklahoma (PSO or Company), as Vice President-Generating Assets filed Rebuttal Testimony on behalf of PSO.

Mr. Knight addressed and responded to assertions made in the direct testimonies of Attorney General (AG) witness Bruce Walter and Oklahoma Industrial Energy Consumers' witness Scott Norwood. According to Mr. Knight, witnesses Walter and Norwood recommended various changes to the level of non-fuel generation operation and maintenance (O&M) expense the Company requested in this proceeding. Additionally, Mr. Knight responded to Mr. Walter's assertion that PSO has provided little support for any of its capital projects, specifically with the installation of the south cooling tower at Tulsa Unit 4 that was placed into service in 2014.

According to Mr. Knight, Mr. Walter stated in his Responsive Testimony that he has not received data necessary to support PSO's O&M expenditures and capital projects such as the south cooling tower replacement at Tulsa Unit 4. Mr. Knight responded by stating that Mr. Walter failed to note that the discovery responses addressing these issues (AG sets 7 and 8) were due to be served to the AG (and all other parties) on October 14, 2015, and October 15, 2015, respectively, in timely accordance with the procedural schedule. Mr. Walter's Responsive Testimony had to be filed on October 14, 2015. Mr. Knight stated that Witness Walter's claim of inadequate data appears to be nothing more than a matter of timing.

My [*sic*] Knight testified that AG witness Walter and OIEC witness Norwood proposed reductions to PSO's test year O&M expenses based on the use of simplistic averages and arbitrary percentage reductions and by summarily dismissing PSO'S well-considered adjustments.

Mr. Knight testified that he requested Northeastern Station's plant manager and team to conduct a comprehensive review of the appropriate level of ongoing O&M expenses considering the retirement of Northeastern 4 in 2016, including the effects on existing common equipment. Mr. Knight explained that the team also conducted a review of the impacts of the additional O&M expenses that would occur because of the new environmental controls to be placed in service on Northeastern 3 in 2016. Mr. Knight stated that the team performed a comprehensive review of the Northeastern 3 and 4 expenses, including an evaluation of each position that was affected by the changes, which resulted in a net reduction of 22 employees. The team also reviewed maintenance expenses, and recommended removal of maintenance costs specifically attributable to Unit 4. In addition, they assessed the impacts of O&M expenses on the common plant and concluded there would be no material change in those costs. The team also provided a forecast of O&M required for the new environmental control equipment.

Mr. Knight disagreed with Mr. Walter's assertion that the generation non-fuel O&M adjusted test year should be decreased by $743,000. Mr. Knight testified that Mr. Walter provided no specific reason or analysis to support his adjustment and that he relied only on his averaging approach. Mr. Knight explained that the adjusted test year methodology is reasonable and the results represent a reasonable level of ongoing O&M expense based on the review of the actual test year expenses by Northeastern 3 and 4 staff, and the post-test year adjustments described in his Direct Testimony.

Mr. Knight stated that he fully rejected Mr. Walter's argument of eliminating incremental expenses or "offsets" that PSO determined were necessary in the adjusted generation non-fuel O&M test year to account for the new environmental controls at Northeastern Unit 3 that would result in an increase to the Northeastern Unit 4 retirement savings of $1,875,000. Mr. Knight explained that Mr. Walter failed to consider the O&M savings would be partially offset to support the dry sorbent injection system (DSI), the fabric filter baghouse (FF), and the activated carbon injection (ACI) system on Northeastern Unit 3. Mr. Knight stated that PSO provided additional support for the offsets in AG's seventh set, question 20, due and submitted on October 14, 2015, the day Mr. Walter's Responsive Testimony was to be filed.

Mr. Knight responded to OIEC witness Norwood's proposed reduction to PSO's generation O&M expense of $6.2 million by assuming that the retirement of Northeastern 4 should generate more savings. Mr. Knight explained that Mr. Norwood gathered Northeastern 3 and 4 O&M expenses from 2012 to 2014 from PSO's FERC Form No. 1 reports, which provides data on a plant level and does not provide O&M separately for each of the units or the common plant. Mr. Knight stated that OIEC witness Norwood estimated an allocation that the Northeastern 4 expenses represent [*sic*] of total plant O&M, but provided no evidence for the basis for his allocation. Using his unsupported estimated allocations for Northeastern 4, he calculated his reduction based only on 2014 O&M expenses, which provide no relevant data on which to base Northeastern 4 O&M expense reductions. Conversely, PSO conducted a methodical review to identify specific items attributable to Northeastern 4, while considering the addition of the new environmental controls at Northeastern 3.

Mr. Knight disagreed with Mr. Walter's proposal to remove $3,448,000 of PSO's generation plant-in service from rate base associated with the Tulsa Unit 4 south cooling tower that went into service in 2014. Mr. Knight stated that Mr. Walter contradicted his own testimony by stating, "PSO provided numerous documents in support of its capital projects, among them several attachments to its response to AG 1-19," in regards to his allegation that PSO had failed to provide support for their capital projects. In addition, PSO comprehensively answered the AG's requests with the appropriate information requested through AG's 7th and 8th requests for information. The attachments provided in AG 1-19, in addition to PSO's responses to data requests, provide the information that witness Walter has requested.

Mr. Knight described the approval process to review and approve the Tulsa Unit 4 South Cooling Tower project.

Mr. Knight testified that Tulsa Unit 4 is a nominal 165 MW natural gas steam cycle unit located in Tulsa, Oklahoma that generally provides peaking capacity to the PSO system.

Mr. Knight stated that Tulsa Unit 4 provides voltage and reactive energy support and "black start" capability to the Tulsa Metro Area. Mr. Knight explained that a "black start" unit can start up under its own power when no electricity is available from the grid to do so. If a "black start" unit were not online should the grid ever collapse, it could be 24 hours or longer for a unit designed to provide "black start" services to come online and begin the process of reenergizing the grid.

Mr. Knight explained that the south cooling tower was an original 55-year old treated Douglas Fir structure with galvanized bolt connections, and was among the oldest original tower structure on the AEP system prior to its replacement. Mr. Knight stated that in February and May of 2009, a series of four cooling tower companies performed a walk-down of this tower and each of the companies agreed the tower was at risk of failure and needed to be replaced. Of particular concern was a catastrophic failure that might have been precipitated by failure of a single structural member that would likely occur with no advance warning.

Mr. Knight gave examples of much younger treated wood, cross-flow cooling towers, comparable to the cooling tower replaced at Tulsa Unit 4, that have experienced partial or complete collapses across the AEP system.

Mr. Knight testified that if the tower had collapsed, PSO would have had to operate the unit with maximum load limited to approximately 50% of the unit's nominal rating. To meet the SPP Capacity Reserve Criteria, PSO would have to enter into a more expensive power purchase agreement.

Summary of the Rebuttal Testimony of A. Naim Hakimi

A. Naim Hakimi, the Director, Power Cost Recovery, for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of Public Service Company of Oklahoma (PSO or Company).

Mr. Hakimi's Rebuttal Testimony responds to Oklahoma Industrial Energy Consumers (OIEC) witness Scott Norwood's recommendation to remove certain Southwest Power Pool (SPP) Integrated Marketplace (IM) related Off-System Sales (OSS) margins from the longstanding Commission approved OSS margin sharing arrangement for PSO.

Mr. Hakimi testified that Contrary to the assertions made by Mr. Norwood, PSO has correctly incorporated the appropriate SPP IM activities into the calculation of its OSS margins, and Mr. Norwood's selection of certain SPP IM activity accounts to be removed from the OSS margin calculation demonstrates a fundamental misunderstanding of the SPP IM. Mr. Norwood not only seeks to remove the net revenues from ancillary services, but he also proposes to remove certain SPP IM accounts that are directly related to the purchase and sale of off-system energy. Mr. Hakimi testified that removing these accounts would leave a distorted and inaccurate calculation of OSS margins.

Mr. Hakimi stated that energy and ancillary services are both competitively procured in the SPP IM and both are required for the reliable functioning of the SPP power market. Contrary to Mr. Norwood's claims, removal of the Ancillary Services Net Revenue accounts from the calculation of OSS margins would create a mismatch in incentives that could impact the efforts of AEPSC, on behalf of PSO, to optimize PSO's generation. AEPSC, on behalf of PSO, optimizes the value of PSO's generation, in part, by participating in both the SPP IM energy markets and the operating reserve markets. The optimization strategy also extends beyond PSO's participation in the SPP IM day-ahead and real-time 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 – both energy and ancillary services. Under Mr. Norwood's proposal, the Company would actually be penalized for this optimization. The Company would be responsible for 25% of the energy margin loss and would receive none of the revenue associated with the ancillary service sale.

Mr. Hakimi stated that sale of ancillary services is an integral part of the Company's optimization strategy in the market. It is clear that when the Commission created an incentive for realization of OSS margins, it intended to encourage the Company to aggressively pursue those sales that are not part of serving native load. The adoption of Mr. Norwood's recommendation would be contrary to the Commission's past orders that provide clear incentives for the Company to pursue the sale of electricity not needed to serve native load customers.

Mr. Hakimi testified that the removal of the accounts recommended by Mr. Norwood from OSS margin sharing fails to recognize their interrelated nature with other OSS margin accounts. This artificial separation could provide outcomes where the Company shares in the losses for the energy part of the OSS transaction, but does not receive a share of the positive revenue from other parts of the transaction recorded in the accounts Mr. Norwood recommends for exclusion from OSS margin sharing. Mr. Hakimi further stated that Mr. Norwood's proposal to remove the net operating reserve and certain other energy sales related revenues from the calculation of OSS margins results in a distorted calculation of OSS margins and should therefore be rejected.

Summary of Rebuttal Testimony of Bruce W. Walter

On November 10, 2015, Bruce W. Walter, Principal, GDS Associates, Inc., filed Rebuttal Testimony on behalf of the Oklahoma Attorney General ("AG"). The purpose of Mr. Walter's testimony was to rebut several assertions made by Dr. Craig Roach, witness for the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission"), regarding the reasonableness of Public Service Company of Oklahoma's ("PSO's") decision to settle with the EPA on PSO's Environmental Compliance Plan ("ECP").

Mr. Walter stated that he did not agree with Dr. Roach's conclusion that the EPA Settlement had the lowest possible risk-adjusted costs among the alternative plans, because two options were estimated to have lower costs in total than the EPA Settlement option. Specifically, the option that involved PSO retrofitting its Northeastern 3 and 4 coal units and allowing them to operate until 2040 had the lowest cumulative present worth ("CPW") of costs across the Low, Base, and High Commodity Price Scenarios. As Dr. Roach stated: "[u]sing PSO's own forecasts of cost, the EPA Settlement is not the lowest reasonable cost option if the forecasts are assumed to be equally probable." Mr. Walter stated that based upon statements made by other PSO witnesses in Cause No. PUD 201200054 ("Cause 54"), Dr. Roach over-stated the risks associated with the admittedly lower cost options. It is Mr. Walter's position that Dr. Roach failed to quantify either the likelihood or the impacts of any of the environmental regulations he (Dr. Roach) contends might cause early shutdown of the Northeastern units.

Specifically, Dr. Roach: (1) failed to present any evidence that the carbon dioxide pricing sensitivities proposed by PSO did not adequately address the economic risk imposed by potential regulation of carbon dioxide emissions, (2) failed to recognize that the proposed conversion of both Northeastern Units to Alstom Dry (NID) technology for SO2 removal would actually reduce the exposure of those units to impacts of future regulation of SO2 emissions in comparison with the technology installed on Northeastern Unit 3 under the EPA plan, (3) failed to show that there was any imminent risk of more stringent regulation of NOx or particulate emissions in Oklahoma, (4) listed water regulations as a risk when the exposure of Northeastern Units 3 and 4 to anticipated regulations is minimal due to the units' use of cooling towers to cool condenser circulating water, and (5) listed ash disposal and effluent guidelines as an additional risk when these factors had already been accounted for in PSO's studies.

In addition, Mr. Walter demonstrated how Dr. Roach failed to recognize numerous examples of bias in PSO's analysis in the inputs to PSO's comparative study of alternative options. These issues included applying a cost of only $6 million for SOFA investments against the EPA Settlement option, but $13 million against the cost of Option #1 – the retrofit of both Northeastern units - costs which had already been incurred when PSO presented its testimony in Cause 54, and simply doubling many single unit costs when applying them to two-unit scenarios, ignoring economies of scales and items that would not cost double (new rail lines, etc.).

Mr. Walter concluded that Dr. Roach failed to demonstrate there is any quantifiable reason to assume that the 25 year cases run by PSO are any more probable than its 15 year cases. His assignment of additional environmental risk to the Northeastern MATS/RHR compliance scenarios, which assumed a 25 year remaining life (until 2041), was purely speculative, unquantified, and unsupported factually. In addition, PSO's studies show evidence of bias in the assignment of costs and do not appear to adequately reflect the cost of replacing capacity lost through the retirement of Northeastern Unit 4 in 2016.

Summary of Rebuttal Testimony of Edwin C. Farrar

Mr. Edwin C. Farrar pre-filed Rebuttal Testimony on behalf of the Attorney General of the State of Oklahoma. Issues addressed by Mr. Farrar included: rate design, cost allocation of purchased power agreements, and margins for power sales into the SPP market.

Mr. Farrar first discussed rate design proposals recommended in the Responsive Testimony of the Public Utility Division Staff ("Staff"), Oklahoma Industrial Energy Consumers ("OIEC"), and the Oklahoma Hospital Association ("OHA"). These parties all recommended allocating any increase in rates in a manner that would move all customer classes close to full cost of service, which would result in a higher increase for residential customers. Mr. Farrar stated that he was concerned with the significant increase requested in this rate case, and stated that a significant move toward full cost of service for residential customers would result in rate shock. He noted that many residential customers have limited financial flexibility. Accordingly, Mr. Farrar recommended that any rate increase be allocated by an equal percentage increase to all customer classes to help mitigate rate shock to the residential class.

Mr. Farrar also rebutted the Responsive Testimony of Mr. Scott Norwood, filed on behalf of OIEC. Specifically, Mr. Norwood recommended that fuel costs related to the replacement purchased power resulting from the EPA settlement be allocated to customer classes on the basis of the production demand allocation factor. Mr. Farrar stated that if a production demand allocation factor is used to distribute the costs to customers, then the residential customers will again be most heavily impacted. Mr. Farrar testified that the purchased power costs are based on energy requirements and so an energy allocator should be used.

Finally, Mr. Farrar supported Mr. Norwood's recommendation in Responsive Testimony that the margins for sales into the SPP market should no longer be shared with the Company. That is because ratepayers bear all of the prudently incurred fuel and purchased power costs and because ratepayers also cover the cost of PSO's production investment in base rates, so customers should be allocated all of the margins from sales into the SPP market. Otherwise, PSO would realize a mark-up on its cost of fuel and purchased power. Mr. Farrar recommended that the Commission adopt Mr. Norwood's recommendation as to this issue.

Testimony of Mr. Steven J. Wooldridge Adopting the Testimony of Charles Matthews

Q. WOULD YOU PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS?

A. My name is Steven J. Wooldridge. My business address is 428 Travis St., Shreveport, LA 71101. I am employed by American Electric Power Service Corporation (AEPSC) as a Principle Transmission Field Services (TFS) Specialist for the Transmission Operations West section.

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Science degree in Electrical Engineering from Virginia Polytechnic Institute and State University in 2007 as well as a Master of Business Administration from Ohio University in 2013. I also obtained my Professional Engineer (PE) license from the State of Ohio in 2011 and am an active PE.

I have worked for AEP for over nine years. I have previously worked in various capacities in the Transmission organization as a Substation Engineer, Technical Support Engineer, and Station Supervisor.

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRINCIPLE TFS SPECIALIST?

A. My current responsibilities include technically supporting western AEP operating companies, AEP Texas Central Company (TCC), AEP Texas North Company (TNC), Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO) to assist with transmission operations, planning and budgeting. I assist the Transmission Field employees with technical support for Construction and O&M projects.

Q. DID YOU FILE TESTIMONY IN THIS CASE?

A. No

Q. WHY ARE YOU ADOPTING MR. MATTHEW'S DIRECT TESTIMONY SUBMITTED IN THIS CASE?

A. He is unavailable to Testify due to personal obligations.

Q. WHY ARE YOU QUALIFIED TO ADOPT THESE TESTIMONIES?

A. I have been involved in the development of the testimony and am familiar with the contents of the testimony.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY OR APPEARED BEFORE EITHER THIS OR ANOTHER REGULATORY COMMISSION?

A. No.

Testimony of Mr. Perry M. Barton Adopting the Testimonies of Mr. Gary C. Knight

Q. WOULD YOU PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS?

A. My name is Perry M. ("Mark") Barton. My business address is 7300 East Highway 88, Oologah, OK 74053. I am employed by the Public Service Company of Oklahoma (PSO or Company), as Plant Manager of the Northeastern Power Stations. PSO is a subsidiary operating company of the American Electric Power Company, Inc. (AEP).

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a degree in Mechanical Engineering from Texas A&M University in 1982. I completed the Management Development Program offered by the Texas A&M School of Business Administration in 1987. I received a Masters in Business Administration from Angelo State University in 1997. I began work for West Texas Utilities as a Results Engineer in 1982; I became a plant manager in 1988, and have held this position in various locations since that time.

Q. WHAT ARE YOUR RESPONSIBILITIES AS PLANT MANAGER OF THE NORTHEASTERN POWER STATIONS?

A. I am responsible for the safe, reliable, efficient and environmentally-compliant performance of PSO's generating assets located in Oologah, OK. More specifically, I oversee and direct the operations and maintenance (O&M) and capital budget expenditures with responsibility for allocation of budget resources to ensure the financial optimization of those generating assets, working with PSO Executive Leadership and the American Electric Power Service Corporation (AEPSC).

Q. DID YOU FILE TESTIMONY IN THIS CASE?

A. No, I am adopting the testimony of Mr. Gary C. Knight.

Q. WHY ARE YOU ADOPTING MR. KNIGHT'S TESTIMONIES SUBMITTED IN THIS CASE?

A. Mr. Knight's schedule and availability to testify have been adversely affected by recent external issues.

Q. WHY ARE YOU QUALIFIED TO ADOPT TESTIMONIES?

A. As a member of the PSO Generation Management Team, I work closely with Mr. Knight and other Plant Managers to appropriately allocate budgets and other resources among the various plant locations, in order to optimize the value of the PSO Generating assets. Interactions with Mr. Knight and other members of this team include weekly and monthly teleconferences, and at least quarterly face-to-face meetings.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY OR APPEARED BEFORE EITHER THIS OR ANOTHER REGULATORY COMMISSION?

A. Yes, in Cause No. PUD 201300128.

III. Statements of Position

Quality of Service Coalition

I. INTRODUCTION

Quality of Service Coalition (QOSC) was established in 2003 by a group of individuals, individual business owners, trade associations, and municipal and county government who were experiencing reduction or lack of services provided by Public Service Company of Oklahoma and other regulated utilities providing electricity and natural gas to Oklahoma customers. The initial focus related to delays in addressing issues raised by customers of Public Service Company of Oklahoma (PSO) for service problems ranging from installation of service, restoration of service, service interruptions and damages resulting from those incidents, to lack of attention to issues like street lighting repair, tree trimming issues, and relocation of facilities, just to name a few.

QOSC used a two prong approach to approach these problems. In the case of PSO, we established a dialogue with PSO to discuss a myriad of issues that our group was experiencing and requesting their attention. At the same time, we became involved in the regulatory process by intervening in cases at the Oklahoma Corporation Commission where PSO and other regulated utilities were seeking regulatory relief. Having a seat at the regulatory table, gave us an additional forum to discuss our issues and seek redress of those issues through the rate and regulatory process.

Significant progress has been made since our organization has been involved. Our membership has, for example, experienced a much improved attention and action to keep street lighting in service which benefits our municipal and county members. A process to meet with governmental entities on various issues was created and continues to provide a method to dialogue on street widening and other infrastructure changes. Realtors and Home Builders Associations had problems establishing electric service which was addressed and is no longer a major problem area. By working with our members, PSO has continued to demonstrate its concern to address customer issues which benefits both the PSO and its customers.

QOSC continues to be concerned with keeping utility rates in Oklahoma at reasonable levels while working with our utilities to provide a strong corporate presence in our communities and our state. Like PSO, QOSC members are individuals, small business owners, realtors, builders, impacted by changes in the economy and those changes can have major ramifications on doing business in our state. For example, the economic debacle, which occurred in 2008 and has carried forward through 2015, has had a major impact on PSO and our members. The real estate market place and the construction of new homes and businesses in Oklahoma continue to rebound slowly. Only now are we beginning to see slight improvement, but this industry still suffers from this problem.

Oklahoma is now facing a similar situation with the decline in pricing of its main industry, the oil and natural gas industry. Not only are prices for those commodities at record lows, but because this vital industrial segment is a large producer of jobs for Oklahoma citizens, reductions in force and spending cut backs are occurring and will continue until this industry begins to recover. Thus, rates and charges are a prime motivation for QOSC's involve [*sic*] in this case.

II. SIGNIFICANT ISSUES

QOSC recognizes the need for periodic rate cases to allow a regulated utility to have rates that are fair, just and reasonable. As an organization made up of business oriented members, we also experience the need to adjust prices to meet the growing needs of our organizations. The issues presented by PSO in this case present a variety of subject matter issues and methods to recover their associated costs. QOSC, in its September 29, 2015, submission of Major Issues of concern identified those issues we think are critical in this case. That list has already been the subject of numerous data requests from QOSC and other parties, and will we [*sic*] vetted as this case proceeds. The following paragraphs relate to significant issues QOSC thinks impact the revenue issues in this case.

For example, PSO proposes an increase in base rates of slightly more than $133 million. In addition, PSO has identified more than $39 million of annual Fuel Adjustment Clause items for a total impact of approximately $172 million. According to PSO testimony, a 10.5% return on equity and an overall rate of return of 7.6% are proposed, while both return percentages were questioned by witnesses for PUD Staff. OIEC, DOD, AG, and WalMart/Sam's [*sic*]expert witnesses suggested lower percentages. Those experts suggest return on equity percentages that ranged from 8.75% to 9.85%. Responsive Testimony experts recommended rate of return percentages that ranged from 6.76% to 7.29%, again below the PSO recommendation. QOSC recommends the Commission review this testimony carefully to determine the appropriate ROE and ROR percentages for this case.

Issues related to the Environmental Compliance Plan (ECP), its implementation (timing), and the costs associated with compliance pursuant to the terms of the Settlement Agreement raise numerous issues for review. Costs proposed for recovery include capital costs for acquisition and installation of plant and equipment. PSO also is recommending the use of accelerated depreciation for Northeastern Station Units 3 and 4. Responsive testimony raises issues related to the appropriateness of changes in current depreciation rates because Northeastern Unit 3 is currently scheduled to operate through 2026, and Northeastern Unit 4 may be considered as a component of a future repowering project to be constructed, in service, and used and useful for Oklahoma retail customers in the 2021-2022 period.

The treatment the Commission gives to just the issues identified above can have an [*sic*] major impact on the revenue deficiency suggested by PSO, and thus, the overall rates and charges PSO customers will pay in the future. These issues coupled with Plant in Service (Test Year and Title 17 O.S. Section 284) requests, adjustments to Operations and Maintenance requests, and federal and state tax calculations can significantly impact the potential increases in rates suggested by PSO.

III. CONCLUSION

Coalition [*sic*] will not present a witness during the hearings [*sic*] on the merits, but Coalition [*sic*] reserves the right to cross-examine witnesses in this matter and to fully participate in all aspects of this proceeding. Coalition also reserves the right to amend this Statement of Position, offer witnesses based on information gathered through future testimony, discovery or a significant change in conditions related to this case should circumstances change or information not previously known becomes available in the course of conduct of this proceeding.

AARP

COMES NOW AARP, by and through its undersigned counsel, and hereby provides its Statement of Position describing the positions that AARP recommends the Oklahoma Corporation Commission (Commission) address in this proceeding. AARP is a nonprofit, nonpartisan membership organization that helps people 50+ have independence, choice and control in ways that are beneficial and affordable to them and society as a whole. 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.

Few government agencies affect consumers' lives as thoroughly as the commissions that regulate utility services. Their decisions affect the cost, quality, and availability of electricity, natural gas, telecommunications, and water. Consumers expect and deserve reliable, safe, and affordable utility service. It is essential to health, safety and economic welfare. Affordable and reliable electric service is require [*sic*] 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 participates in general rate cases on behalf of its members because such cases offer an opportunity for regulators to conduct a full and complete review of a utilities [*sic*] expenses and revenues and address important policy issues that impact customers. Vertically-integrated utilities in Oklahoma operate as state-sanctioned monopolies where regulation and oversight by the Commission stands in as a proxy for competition and as a restraint on price and terms of service for the protection of consumers. In additional to traditional issues that impact rates like setting return on equity, capital structure, [*sic*] depreciation rates, among other items, the Commission is also being asked to address treatment of costs in non-traditional manners and approve recovery of costs from customers even before the utility incurs such costs. AARP respectfully requests the Commission evaluate the evidence submitted in this matter and make determinations consistent with the following recommendations.

1. Award Return on Equity of 8.75%

PSO is requesting the Commission approve a 10.50% return on its equity in this case. This amount results in an excessive return on PSO's parent's equity participation in PSO's utility service. This excess return flows to PSO's only equity investor, AEP, at the expense of PSO's customers and the Oklahoma economy by paying more than what is required for reasonable electric service.

Respondents in this case calculate various ranges of potential percentages for ROE. For example, the AG recommends an ROE of 8.75%, the OIEC recommends ROE at 9.125%, and PUD Staff calculates the ROE to be less than 8% but recommends an ROE of 9.25%. Note that none of these calculations get anywhere close to 10.00%, nevertheless the 10.50% PSO's requesting. PSO's requested ROE is excessive and, if adopted, will result in unreasonable rates to its customers.

AARP notes that PSO is not entitled to payments from customers based on inflated ROE [*sic*] would fall outside the establishment of fair, just and reasonable rates. ROE should be established in each rate case based on the then-existing required returns on equity for similarly situated entities. PUD Staff calculated PSO's ROE to be less than 8.00%,[14] therefore adopting the AG's proposed ROE of 8.75% would be a more than adequate ROE to compensate AEP's shareholders. Therefore, AARP advocates the Commission determine that a ROE of 8.75% is fair, just and reasonable in setting rates for PSO in this case.

2. Use PSO's Actual Capital Structure of 56% Debt and 44% Equity

PSO is asking this Commission to apply to it a capital structure that does not exist, in order to receive additional revenues from customers to which it is not entitled. PSO's actual capital structure is made up of 56% low cost debt and 44% equity capital. However, PSO wants the Commission to pay it based on using less low cost debt (52%) and more high cost equity (48%).

As described by PUD Staff witness Garrett, competitive companies seek to finance as much of their operations as possible with low cost debt, whereas utilities do not have these same types of incentives to reduce their weighted average cost of capital.[15] Because utilities do not have these incentives naturally, sometimes regulatory bodies have to impose a hypothetical capital structure that is more reasonable by reducing the amount of equity utilized in setting rates.

However, PSO is turning the normal concern of a utility using too much equity on its head by asking the Commission to impose a hypothetical capital structure to artificially increase the amount of more expensive equity capital than it otherwise used to actually finance its operations. This creates an improper increase in the cost of electric service that customers would be required to pay. Because of this, AARP advocates the use of PSO's actual capital structure of 56% debt and 44% equity and reject the use of a more expensive hypothetical capital structure.

3. Reject $25.4 Million of PSO's Requested Increase in Depreciation Expense

PSO identified that approximately $35,000,000 of its requested annual rate increase is due to higher levels of depreciable plant, along with a proposed increase in depreciation rates.[16] It appears based on the evaluation conducted by OIEC depreciation expert Mr. Pous, PSO is essentially asking for a 50% increase in depreciation expense that is directly related to an increase in depreciation rates and that very little of the increase can be attributable to increases in depreciable plant.[17]

In order to address this aggressive request [*sic*] PSO, PUD Staff has proposed an adjustment to correct this by decreasing depreciation expense by $25.4 million.[18] AARP agrees

[14] Staff calculated PSO's actual ROE to be below 8.00%, but then recommended a 9.25% ROE, stating that it was "recommending an awarded return on equity that is well above the true required return on equity." PUD Staff witness Garrett Cost of Capital Resp. Test., Oct. 14, 2015, pp. 60 & 104.
[15] PUD Staff witness Garrett Cost of Capital Resp. Test., Oct. 14, 2015, p. 60-70.
[16] PSO witness Sartin Dir. Test., July 1, 2015, p. 8.
[17] OIEC and Wal-Mart witness Pous Dir. Test., Oct. 14, 2015, p.3 ll.1-7.
[18] PUD Staff Garrett Depreciation Resp. Test., Oct. 14, 2015, p.25 ll.1-11.

that PSO's request for a 50% increase in depreciation rates is not appropriate and supports PUD Staff's adjustment to remove $25,400,000 of PSO's requested depreciation expense.

4. Remove from Rates Incentive Compensation Costs Tied to AEP's Stock Price Performance and Supplemental Executive Retirement Plan Costs

There are several types of additional compensation costs included in PSO's application that are contrary to Commission policy on these matters. PSO is requesting to include in rates $13,122,644 annually for these incentives. In the past, the Commission has only allowed recovery of 50% of short-term incentives and none of the costs of long-term incentives or Supplemental Executive Retirement Plans in rates paid by customers.

With regard to short-term incentive plans, the Commission has not allowed in rates the portions of incentive plans that are tied to a utility's stock performance, as those incentives promote behaviors that benefit shareholders and should pay for themselves with the benefits of increased financial performance it creates for shareholders. The Commission has allowed recovery from ratepayers the portions of incentives that are tied to performance activities that provide direct benefits to customers.

However, since the Commission last reviewed PSO's short-term incentive plan, two major changes have occurred: (1) AEP has modified the plan so that 75%, not 50%, of the incentive is tied to AEP's financial performance[19] and (2) AEP has failed to pay incentives and retained the money for shareholders.[20] Because short-term incentives are now driven more heavily by financial performance, rather than equally driven by financial performance and customer-beneficial activities, and whether to pay out any incentives is driven entirely by financial performance, the Commission should disallow 100% of all short-term incentive costs from rates. This reduces PSO's expenses by $8,739,895.

The Commission has long rejected executive long-term incentive compensation because it is solely tied to the financial performance of the company. The Commission has also continuously rejected the recovery from ratepayers of supplemental executive pension plans that provide highly paid executives with pension benefits above and beyond the pension benefits normally provided by the Company. Therefore, AARP supports the continued exclusion from rates the executive long-term incentive and supplemental executive pension plan costs. This action reduces PSO's expenses by $4,382,749.

5. Use of Riders to Collect Costs from Customers – Terminate SRR Rider and Add Termination Date of December 31, 2016, to AMI Rider

AARP believes that surcharges and riders have grown beyond the point of reasonableness in Oklahoma and need to be reined in order to establish greater balance to the ratemaking process and to restore appropriate cost incentives for PSO. The costs to provide utility service should not be collected through piecemeal surcharges in the form of riders, but rather through base rate cases where all expenses and revenues can be identified and evaluated prior to allowing cost

[19] "The 2014 annual incentive plan was primarily funded based on AEP's earnings per share (EPS) (75 percent weight)." PSO witness Carlin, Dir. Test, July 1, 2015, p. 17.
[20] See OIEC witness Garrett Resp. Test, Oct. 14, 2015, p. 21 fn 15 & p. 30.

recovery. As seen in the proliferation of surcharges that PSO's [*sic*] utilizes–apparently now numbering at least 20–it collected over $233,000.000 in non-fuel costs in 2014 instead of through the base rates.[21] Therefore, PSO is [*sic*] collected a staggering 43% of its operating revenues through surcharges, and if you include fuel recovery, PSO collects more than 70% of its revenues outside of the rate setting process.[22]

Surcharges also result in additional undesirable consequences such as removing utility incentives to control costs and improperly shifting utility business risks away from shareholders (who are the ones in a position to identify and address such risks) and onto customers. As such, surcharges and riders ultimately cause the bills that consumers must pay to be higher than necessary. Thus, surcharges 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.

PUD Staff recommends the Commission adopt the following criteria for evaluating rider requests: Are the costs volatile and unpredictable? Are the costs outside the utilities [*sic*] control? And are the costs substantial and reoccurring? AARP agrees that applying consistent criteria are important to consistent and balanced policy application, however, just because a cost may be substantial and reoccurring is no reason for approving rider recovery. Substantial cost categories are regularly included in base rates. The evaluation of "substantial and recurring costs" is modified by a review of whether such costs could financially harm the utility if not dealt with immediately outside of rate case. Below is the list of criteria that AARP advocates regulatory bodies follow when evaluating recovery requests from a utility:

1. Largely outside the control of the utility,
2. Unpredictable and volatile, AND
3. Substantial and reoccurring, <u>and which would have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a traditional rate case.</u>

When such circumstances exist and a surcharge is instituted, the Commission should include minimum customer safeguards such as: limiting the use of the number and size of riders for any one utility; recovering only clearly defined costs (with cost overruns borne by shareholders) for a specific amount of time and conduct a full audit and review; rate of return should be adjusted downward for the revenue stream provided by a rider; and any efficiencies or cost savings that a rider provides should be included to reduce rider charges.

Because of the extensive number of riders (over 20) and the significant sums of revenue PSO is collecting from customers (some 70% of revenues), AARP requests the Commission evaluate each rider based on the criteria above and determine whether there is a need for each specific rider and terminate riders as may be appropriate.

PUD Staff makes the recommendation to begin to pare down PSO's riders in this case. For the System Reliability Rider (SRR Rider), Staff recommends folding all of the costs

[21] See PSO response to discovery request AG 3-1(a) and (b).
[22] See PSO response to discovery request AG 3-1(a) and (b).

currently collected through the rider into base rates and then terminating the rider.[23] Staff also identified that the Advanced Metering Infrastructure (AMI) rider should be modified to include a sunset date, but does not appear to make a specific recommendation as to what that date should be.[24]

As to the SRR Rider, AARP supports staff's recommendation to terminate this rider. However, in Cause No. PUD 2013-217, AARP raised concerns about PSO's recovery of more than $23,000,000 through this rider (which recovered over $21,000,000 in 2014). In addition, AARP also identified that there is more than $5,000,000 for similar O&M costs already being collected in base rates. AARP recommends the Commission terminate the SRR Rider without moving costs into rate base and require PSO to make a showing that the costs that were collected previously through the rider are prudent, necessary and reasonable before including such costs in rates.

With regard to the AMI rider and its future termination, Staff identified in PSO's last rate case (Cause No. PUD 2013-217) that all of PSO's service territories are to have advanced meters installed by the end of the 3rd quarter of 2016, with any remaining meters to be installed in the 4th quarter of 2016.[25] Therefore, AARP recommends the AMI rider include an automatic termination date of December 31, 2016, which coincides with the date that PSO represents that its AMI installation would be completed.

6. **Cost Allocation Should Recover Any Rate Increase in Equal Percentage Across Customer Classes**

Cost allocation and rate design are an art not a science. Moreover, the preparation of a cost of service study is made through hundreds, perhaps thousands, of subjective decisions as to how to allocate plant to determine an estimate of a cost to service each of a utility's various customer classes. PSO does not request any changes in its rate design, and proposes that all classes receive an equal percentage rate increase. While AARP disagrees with PSO's requested rate increase, it does agree that there should be no changes to PSO's rate design and supports allocation of any increase on an equal percentage basis across customer classes.

Affordable electric rates for the individual citizens of Oklahoma are of paramount importance when determining cost allocation. Individual ratepayers, not businesses, may have their health and quality of life impacted by utility rates. 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.

PSO's residential class has been hit hard with numerous recent increases in costs: they bear a significant amount of the costs of the demand side management rider; PSO's AMI program is a predominantly a [*sic*] residential program in which the residential class again bears a majority of the costs. These actions have resulted in large recent additional rate burdens on the residential class that would only be exacerbated if the residential class is required to shoulder a

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[23] PUD Staff witness Champion Resp. Test., Oct. 23, 2015, pp. 11-12.
[24] PUD Staff witness Champion Resp. Test., Oct. 23, 2015, p. 15.
[25] See Resp. Test. of Hinex-Ford, Cause No. PUD 2013-217, April 23, 2015, p.11.

significantly larger rate increase than other classes. AARP recommends the Commission reject any cost allocation that assigns an excessive rate increase on PSO's residential customers compared to other customer classes.

7. Reject Expansion of the Fuel Adjustment Clause to Recover Non-Fuel Costs

PSO estimates that in the future it may incur approximately $4,000,000 per year in certain air quality control system consumable costs that it would like to recover not through rates, but rather through a modification to its fuel recovery mechanism. These expenses are not for fuel. They are consumable materials that are to be incurred in the future and are based on estimates that could well exceed current estimates.

PSO failed to identify any evidence that would support the need for recovery through the FAC as opposed to recovery through rates. PSO may claim that these costs vary with the production of electricity, however, many utility costs vary with the amount of electricity it produces, but this does [*sic*] mean they are fuel costs to be recovered via the fuel adjustment clause. Therefore, AARP recommends the Commission reject PSO's request to modify its fuel adjustment clause to recover non-fuel consumable material costs, and determine that recovery shall occur only through base rates.

8. Reject ECR Rider Requested by PSO for Recovery of Environmental Compliance Costs and Allow Recovery in Base Rates

PSO is requesting to establish a new rider to recover environmental compliance costs outside of its base rates. AARP does not support the use of surcharges for cost recovery of known and measurable expenses. PSO should be required to recover such costs through an evaluation of its entire revenue need as conducted in a rate case. In this case, the Commission should evaluate the costs incurred in the test year, and Oklahoma's expanded use of looking at costs and revenues up to six months beyond the test year, to compensate the Company for its actual expenditures. Should future year costs for environmental compliance outstrip growth in revenues, the Company should file a subsequent rate case to evaluate the Company's need. Therefore, AARP recommends the Commission reject the use of a rider to recover environmental compliance costs and allow recovery of costs actually incurred by the utility in the test year through the setting of base rates.

9. PSO Should Remove Distribution Costs Embedded in its Fixed Monthly Customer Charge

AARP believes that PSO's customers should not be subject to its move toward decoupled rates through incremental moves to a Straight Fixed Variable rate design. This has been accomplished by collecting certain distribution costs through its fixed minimum monthly bill charge of $20.00 per month for residential customers.[26] This decision to move from variable cost recovery through kilowatt hour costs into a fixed component in a customer's monthly bill charge is not in the public interest and should be reversed.

[26] See rate schedules reflected in Section N of PSO's Application Package filed herein on July 1, 2015.

In general, lower income and elderly customers have lower usage than the average residential customer due to smaller dwellings, and, with respect to elderly, their smaller household size. As a result, an increase in the fixed monthly customer charge has a more adverse impact on customers who can least afford to pay these charges.

It does not appear that any other AEP jurisdictions have implemented such rate design modifications because AEP's other jurisdictions have monthly service charges ranging from $7.30 to $9.25 per month, much lower than the charge of $20.00 per month Oklahoma ratepayers are subjected to. It may even be fair to say that Oklahomans on PSO's system pay one of the highest monthly charges in the country. AARP requests the Commission direct PSO to remove all distribution-related charges from its fixed monthly charge, and move all such costs back into the variable kilowatt hour charge.

SUMMARY OF AARP POSITIONS AND RECOMMENDATIONS

1. Award Return on Equity of 8.75%

AARP advocates the Commission determine that a ROE of 8.75% is fair, just and reasonable in setting rates for PSO in this case.

2. Use PSO's Actual Capital Structure of 56% Debt and 44% Equity

AARP advocates the use of PSO's actual capital structure of 56% debt and 44% equity and reject the use of a more expensive hypothetical capital structure.

3. Reject $25.4 Million of PSO's Requested Increase in Depreciation Expense

AARP agrees that PSO's request for a 50% increase in depreciation rates is not appropriate and supports PUD Staff's adjustment to remove $25,400,000 of PSO's requested depreciation expense.

4. Remove from Rates Incentive Compensation Costs Tied to AEP's Stock Price Performance and Supplemental Executive Retirement Plan Costs

Because short-term incentives are now driven more heavily by financial performance, rather than equally driven by financial performance and customer-beneficial activities, and whether to pay out any incentives is driven entirely by financial performance, the Commission should disallow 100% of all short-term incentive costs from rates. This reduces PSO's expenses by $8,739,895. AARP supports the continued exclusion from rates the executive long-term incentive and supplemental executive pension plan costs. This action reduces PSO's expenses by $4,382,749.

5. Use of Riders to Collect Costs from Customers – Terminate SRR Rider and Add Termination Date of December 31, 2016, to AMI Rider

Because of the extensive number of riders (over 20) and the significant sums of revenue PSO is collecting from customers (some 70% of revenues), AARP requests the Commission evaluate each rider to determine whether there is a need for each specific rider and terminate riders as may be appropriate, by evaluating if the costs collected are:

(1) outside the control of the utility,
(2) unpredictable and volatile, and
(3) substantial and reoccurring, and which would have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a traditional rate case.

AARP recommends the Commission terminate the SRR Rider without moving costs into rate base and require PSO to make a showing that the costs that were collected previously through the rider are prudent, necessary and reasonable before including such costs in rates. AARP recommends the AMI rider include an automatic termination date of December 31, 2016, which coincides with the date that PSO represents that its AMI installation would be completed.

6. Cost Allocation Should Recover Any Rate Increase in Equal Percentage Across Customer Classes

AARP recommends the Commission reject any cost allocation that assigns an excessive rate increase on PSO's residential customers compared to other customer classes.

7. Reject Expansion of the Fuel Adjustment Clause to Recover Non-Fuel Costs

AARP recommends the Commission reject PSO's request to modify its fuel adjustment clause to recover non-fuel consumable material costs and determine that recovery shall occur only through base rates.

8. Reject ECR Rider Requested by PSO for Recovery of Environmental Compliance Costs and Allow Recovery in Base Rates

AARP recommends the Commission reject the use of a rider to recover environmental compliance costs and allow recovery of costs actually incurred by the utility in the test year through the setting of base rates.

9. PSO Should Remove Distribution Costs Embedded in its Fixed Monthly Customer Charge

AARP requests the Commission direct PSO to remove all distribution-related charges from its fixed monthly charge and move all such costs back into the variable kilowatt hour charge.

AARP'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. AARP 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.

The Alliance for Solar Choice

COMES NOW, the Alliance for Solar Choice ("TASC"), by and through its undersigned counsel, and hereby files the following Statement of Position in the above-styled Cause, in response to the Application of the Public Service Company of Oklahoma ("PSO") to initiate a proceeding to review its rates, charges, regulations and conditions of service and for the establishment of fair and reasonable rates and charges, including for certain environmental compliance upgrades, upon completion of the Oklahoma Corporation Commission ("Commission").

TASC does not plan to present a witness during the hearing on the merits beginning December 8, 2015, but reserves the right to cross-examine the witnesses presented during the hearing and to fully participate in all aspects of this proceeding. TASC reserves the right to amend this Statement of Position or offer witnesses based on information gathered through future testimony, discovery or a significant change in condition related to this Cause should such circumstances change or otherwise present new information not previously known becomes available in the course of the proceeding. Any issues not addressed and any comments not expressed below should not be construed as agreement with PSO's position, method or procedures relating to its Application.

As an initial matter, TASC is pleased to see PSO's recognition of the value of solar energy, as evidenced by its inclusion of utility-scale solar in its 2015 Integrated Resource Plan and its commitment to conduct a Request for Proposals ("RFP") to explore adding additional cost effective utility-scale solar resources in the future. Additionally, TASC believes that PSO's plan to include utility-scale solar is a good initial step that will deliver significant benefits to consumers, businesses and society by, among other things, providing water savings, fuel price hedging, energy security, energy resilience, reduction in both installed and ongoing operations and maintenance costs, less lead time than other forms of generation, greenhouse gas reductions and criteria air pollutant reductions. Further, TASC notes PSO's recognition of the importance of actively supporting Oklahomans in their decision to employ Distributed Generation ("DG") and the benefits DG can bring to Oklahoma today and into the future.

Notwithstanding the former, TASC believes PSO's utility-scale planned additions to be modest given the intrinsic benefits of solar generation and the large opportunity that Oklahoma's solar resources can provide. TASC believes it should also be noted that DG solar can provide additional benefits for DG adopters and non-adopters alike, as highlighted by numerous recent studies.[27] These benefits included avoided energy costs, environmental compliance costs, future capacity investments, transmission and distribution line loses [*sic*], and enhanced geographic resource diversity, energy security and resilience. Unfortunately, PSO fails to recognize the enormous potential of roof-top solar and other attractive forms of DG available to Oklahomans. Even PSO's modest DG projections are made more questionable when one considers they have not projected the potential negative impact and future risk to customers of the Utility pursuing and possibly achieving an unfair DG Tariff. Such a tariff might serve as a tax-like disincentive

[27] *See* Intersate Renewable Energy Council, Inc. A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation. Available at:
http://www.occeweb.com/pu/DistributedGeneration/Benefits%20and%20Costs%20of%20Solar%20DG.pdf
See Stanton, A., et al. Net Metering in Mississippi: Costs, Benefits, and Policy Considerations. Prepared for the Public Service Commission of Mississippi. Available at: http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf
See National Renewable Energy Laboratory. Distributed Solar PV for Electricity System Resiliency. Available at: http://www.nrel.gov/docs/fy15osti/62631.pdf

and ultimately impede Oklahomans ability to afford DG additions to their family homes or businesses.

Further, PSO's Rate Case at issue here could have explored the subject of a DG tariff within this Cause, where a current cost of service and other financial data is widely available to more properly vet the requirements of weighing the costs and benefits in a fair and equitable manner for DG integration to PSO's system. This missed opportunity is not only a poor use of judicial economy, but a standalone tariff application, filed outside of a rate case, raises legitimate concerns, including but not limited to, whether a rate considered in isolation can be truly revenue neutral. Should PSO decide to abandon the more reasonable approach of including a DG tariff within this Cause, TASC takes this opportunity to strongly urge PSO to utilize the Commission's DG Tariff Checklist, which resulted from the Commission's seven (7) month analysis and series of public meetings concluding on March 31, 2015, wherein the Commission thoroughly explored Distributed Generation issues, costs, benefits and technological opportunities, for Oklahoma. The DG Tariff Checklist provides the foundation for fair and equitable consideration and treatment of DG resources. As a participant in the process that lead to the DG Tariff Checklist, PSO undoubtedly recognizes the benefits of the development and inclusion of a mechanism within the Commission's examination process which clearly defines the benefits and cost of DG resources. Done incorrectly, a DG Tariff could evaporate PSO's modest commitments to use of solar, and limit the potential of the solar industry, DG and the numerous benefits they can provide to Oklahomans.

IV. Findings of Fact and Conclusions of Law

Jurisdiction

The ALJ recommends that the Commission find that Applicant is Public Service Company of Oklahoma, a corporation incorporated within the State of Oklahoma, authorized to do business in the State of Oklahoma. Further, that Applicant is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electric power and energy at wholesale and retail levels within the State of Oklahoma. The ALJ recommends that the Commission find that it has jurisdiction over this Cause by virtue of the provisions of the Constitution of the State of Oklahoma, specifically Article IX, Sections 18 and following, 17 O.S. 2001, §§ 151 *et seq.*, and the Rules and Regulations of this Commission, including the Commission's Minimum Standard Filing requirements as set forth in OAC 165:70. The ALJ recommends that the Commission find that proper notice of these proceedings was given as required by law and the orders of this Commission.

Test Year

The ALJ recommends that the Commission adopt PUD's recommendation to adjust Plant in Service and related accounts from the January 31, 2015 test year balances to the July 31, 2015, six-month post-test year balances. PUD witness Robert Thompson proposed these adjustments and cited 17 O.S. § 284, which states, "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." (Pre-filed Testimony of Robert Thompson, October 14, 2015, page 8, lines 13 – 21)

Mr. Thompson testified that PSO provided updated Schedules C (Plant in Service) and D (Accumulated Depreciation as of January 31, 2015, in response to the Attorney General's First Set of Data Requests to PSO, and also information about electric plant addition projects costing more than $1 million. In addition, PUD requested information regarding large invoices, most of which were for capital assets. Direct Testimony filed on behalf of PSO consistently indicated the need for investments in plant mostly for environmental and safety issues for production plant, and reliability issues for transmission and distribution plant. Mr. Thompson recommended that the test year balances for Plant and related accounts be updated to the 6-month post-test year balances. (Pre-filed Testimony of Robert Thompson, October 14, 2015, page 8, line 24 – page 9, line 10) The ALJ recommends the Regulatory Asset proposal of the PUD including any exceptions noted herein. The ALJ recommends the Regulatory Liabilities proposal of the AG be adopted with the upward adjustment that was also adopted by PSO and proposed by the AG.

Environmental Compliance Plan

The ALJ recommends that the Commission find that PSO's ECP is prudent, and that therefore, cost recovery is warranted. The ALJ recommends that the Commission find that cost recovery should be approved through the base rate approach for PSO's ECP, but only with the following important conditions:

First, the ALJ recommends that the Commission find that PSO should be held to a hard cap for its DSI/ACI/FF investment at Northeastern 3. The hard cap should be set at $210 million, which is the cost estimate PSO used for the investment in evaluating the ECP against other alternatives in Cause 54. Specifically, under the hard cap, PSO may not seek recovery of more than $210 million adjusted appropriately for allowance for funds used during construction ("AFUDC") and overhead, regardless of the timing of cost recovery.

Second, the ALJ recommends that the Commission find that PSO should not be allowed to recover any costs for its Comanche Dry Low NOx burners until the investments are in service. This condition also includes rejection of the test-year waiver.

Third, the ALJ recommends that the Commission find 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. To mitigate rate increases, depreciation for the undepreciated, "original" costs of these two units should continue on its current pace to 2040.

Fourth, the ALJ recommends that the Commission find that PSO should be required to seek approval in this proceeding through rebuttal testimony for PSO's SOFA investments on Northeastern Units 3 and 4, Southwestern Unit 3, and the majority of its investment in Northeastern Unit 2. While PSO claims to have received approval for these expenditures, and PSO has already included these investments in rate base, PUD has not seen evidence that the Commission has granted explicit approval for these investments. PUD has no reason at this time to argue against cost recovery for these investments, but the Commission must be given the opportunity for an explicit approval.

Fifth, the ALJ recommends that the Commission find that PSO should be required to seek approval for all three power purchase agreements related to replacing the power from the retired Northeastern Unit 4. PUD has previously supported and supports here cost recovery for the Calpine power purchase agreement ("PPA"). PUD has no reason at this time to argue against cost recovery for the other two PPAs, but the Commission must be given the opportunity for an explicit approval of all three PPAs.

Sixth, the ALJ recommends that the Commission find that the Commission should not rule on the prudence of the planned retirement of the retrofitted Northeastern 3 unit in 2026 until a Commission hearing is held in or about 2020. The same would go for a ruling on the capacity factor limitations for that unit. This condition is given added support by the fact that PSO itself is unsure what it will do with Northeastern 3 in 2026 – as evidenced by its extensive analysis in this proceeding of converting the unit to natural gas at that time and by its recent analysis of repowering the unit in PSO's Integrated Resource Plan ("IRP") update.

Construction Work in Progress (CWIP)

Since the Commission has adopted the Utility Plant in service balance as of July 31 2015, the ALJ finds that no CWIP should be included in the rate base of PSO. No adjustment is necessary to reflect this decision, since the booked utility plant in service as of July 31, 2015, captures all CWIP requested for those plants that were actually placed in service as of July 31, 2015.

The ALJ finds that it is not appropriate or necessary to extend CWIP for any portion of the ECP costs. As PSO witness Thompson acknowledged, his recommendation to allow PSO CWIP treatment for a portion of its environmental costs is a departure from the Commission's decisions in recent years. (*See* 12/21/15 Tr., pp. 191-192). Under 17 Okla. Stat. § 284, including in rate base actual plant in service balances as of July 31, 2015, which is six months after the end of the test year, is proper. However, the Commission has consistently held that projects still in CWIP accounts at the date of the six-month cut-off have been excluded. For example, in ONG's 2005 rate case, Cause No. PUD 200400610, the first major rate case heard by the Commission after passage of the 6-month rule in Title 17 § 284, the ALJ adopted, and the Commission approved, the approach of including updated plant in service as of the 6-month cut-off date, and excluding amounts in the CWIP accounts. Also, in OG&E's 2005 rate case, PUD 200500151, the Commission again approved this approach, updating the Plant and Accumulated Depreciation balances to six months after test year end and appropriately excluding CWIP on the books at that time. Also, in PSO's last two litigated rate cases, Cause No. PUD 200600285 and Cause No. PUD 200800144, the Commission followed this approach. In short, this treatment has been consistently adopted because it has the effect of including in rate base all projects actually complete and in service within the 6-month post test year period.

PSO's evidence was that of the $61 million in costs of environmental investments PSO seeks to recover, approximately $44 million of investments will not be in service at the end of the 6-month, post-test year period. (*See* Sartin cross, 12/8/15) Under the evidence presented by PSO, neither the Northeastern Unit 3 nor the Comanche plant has a completion date that was imminent on July 31, 2015, the conclusion of the 6-month cut-off. Both plants have estimated completion dates in 2016, and it is clear from PSO's application that the Comanche plant will not be placed in service until at least June 2016, which is 17 months beyond test-year end. (*See*

Sartin cross, 12/8/15 Tr., p. 105). The Commission finds that these estimated completion dates do not justify CWIP recovery. PSO witness Sartin admitted at the hearing in this cause that these investments are not currently used and useful. *Id.* Mr. Sartin did not know of any instances where the Commission had authorized investments in rate base when the plant was not used and useful and in service until after the 6-month, post-test year end. (*See* Sartin cross, 12/8/15 Tr., p. 148).

The ALJ does not adopt PSO's proposals to recover the estimated $44.2M annual costs associated with ECP assets that will not be in service until later next year by either (1) extending the rate base out for an additional 17-month period beyond test year end or (2) recovering the costs through the proposed Environmental Compliance Rider ("ECR"). The ALJ also does not adopt Staff's proposed middle-ground position of including the CWIP balances at July 31, 2015 for the ECP assets. The ALJ finds that there is not sufficient evidence in this case to warrant a departure from the long-standing ratemaking policy. PSO may, if necessary and if it so chooses, bring a general rate proceeding to recover the ECP costs once the facilities have been placed in service, if the utility believes it is earning an insufficient return at that time.

Cost of Capital

The ALJ recommends that the Commission find and adopt the following cost of capital items: 1) a cost of equity of 9.25 percent, which is the highest point in a range of reasonableness of 8.75 to 9.25 percent; 2) a cost of debt of 4.92 percent, as proposed by PSO; 3) a capital structure consisting of 56 percent debt and 44 percent equity; 4) an overall weighted average cost of capital of 6.83 percent, which is the highest point in a range of reasonableness of 6.61 to 6.83 percent; and 5) an adjustment of $8,152,488 to reduce pro forma incentive compensation expense. The ALJ recommends that the Commission find that these cost of capital items are fair, just, and reasonable to both ratepayers and PSO.

The ALJ recommends the Commission find that an adjustment to the ROE to account for flotation costs is unnecessary because the risk associated with flotation costs is already incorporated into the ROE. Flotation risk is accounted for when choosing a proxy group of publicly traded parent companies that issue stock and incur such costs. The Commission has not previously authorized a flotation cost adjustment, as the Company confirmed in response to DOD/FEA Discovery Request 3-6. (*See* Hearing Exhibit 20).

Rate of Depreciation

The ALJ recommends that the Commission find an adjustment of $23,014,546 to reduce PSO's proposed depreciation expense. The ALJ recommends that the Commission find that this adjustment is fair, just, and reasonable to both ratepayers and PSO.

Current Rate Case Expense

The ALJ recommends that the Commission find that the assessment of costs for PUD and AG witnesses shall be based on Commission Order No. 643363 (Order Granting Public Utility Division's Motion for Assessment of Costs) and Commission Order No. 644100 (Order Granting Attorney General's Motion for Assessment of Costs), and that these costs shall be amortized over a two-year period and recovered from the ratepayers in the amount as ordered by the Commission.

Prior Rate Case Expenses

The ALJ recommends that the Commission find an annualized adjustment in the amount of $555,601 and an amortization over 24 months is fair, just, and reasonable.

AEPSC Adjustments Billed to Rate Case Expense

The ALJ recommends that the Commission find an adjustment to decrease AEPSC overhead incentive expenses in the amount of ($131,493) that were added in rate case expenses to be fair, just, and reasonable.

Taxes other than Income Taxes

The ALJ recommends that the Commission find an adjustment of a decrease in the Federal Insurance Contribution Act tax of $83,433 and a decrease of $190,749 for Franchise and Excise Tax are fair, just, and reasonable.

Bad Debt expenses

The ALJ recommends that the Commission find PSO's proposed ($221,598) decrease for the factoring is fair, just, and reasonable.

Fuel and Purchase Power Revenues

The ALJ recommends that the Commission find that PSO's proposed adjustment to remove $791,339,138 of fuel-related revenue collected under the OCC-approved Fuel Adjustment Clause ("FAC") from the rate base revenue requirement is fair, just and reasonable. The ALJ recommends that the Commission find that there are four (4) adjustments, including WP H-2-22 Purchased Power revenue adjustment ($37,354,310), WP H-2-23 revenue adjustment ($750,301,127) and WP H-2-25 Miscellaneous revenue adjustment ($3,683,701). The ALJ recommends that the Commission find that all fuel-related revenue has been moved into the FAC.

The ALJ also recommends that the Commission find that PSO's proposed four adjustments to remove $695,152.152 of fuel expenses recovered under the FAC from the rate base are fair, just, and reasonable, and that they are consistent with Commission Order No. 639314 in Cause No. PUD 201300217, which removed fuel related revenues and expenses from base rates.

O&M Generation Non-Fuel

The ALJ recommends that the Commission find that PSO's approach and adjustments regarding the O&M Generation Non-Fuel are fair, just, and reasonable.

Informational/Instructional/Miscellaneous-Sales Expense

The ALJ recommends that the Commission find that PUD's proposed Adjustment No. H-10 amount of $183,241 concerning expenses for Edison Electric Institute ("EEI"), lobbying expense, Chamber of Commerce, Hugo Lions Club, etc., do not appear to benefit ratepayers exclusively and, therefore, should not be recovered from ratepayers. The ALJ recommends that the Commission find that these kinds of expenses should be shared between ratepayers and stockholders. The ALJ also recommends that the Commission find an adjustment of $110,427 ($114,263 - $4,836 BNSF Railway costs that were outside of the test year and not included in PSO's request).

Prepayments

The ALJ recommends that the Commission find that PUD's adjustment No. B-8 to decrease the prepayment balance by ($1,709,670) is fair, just, and reasonable.

Employee Group Insurance

The ALJ recommends the Commission adopt the adjustment to reduce employee medical expenses by $864,257 as recommended by DOD/FEA witness Morgan. As indicated in the Rebuttal Testimony of PSO witness Hamlett, the Company does not contest this adjustment proposed by Mr. Morgan. (*See* Hamlett Rebuttal Testimony, p. 53:5-9).

Customer Deposits

The ALJ recommends that the Commission find that PUD's adjustment No. B-1 to decrease the customer deposits account by ($1,609,152) is fair, just, and reasonable.

Off System Trading Deposits

The ALJ recommends that the Commission find that PUD's adjustment No. B-5 to increase the off system trading deposits balance by $876,539 is fair, just, and reasonable.

Materials, Supplies[28]

The ALJ recommends that the Commission find that PUD's adjustment No. B-2 to decrease the materials, supplies account by $(182,869) is fair, just, and reasonable.

Payroll Expenses

The ALJ recommends that the Commission find that PUD's adjustment which will decrease Payroll Expenses in the amount of ($1,500,134.36) to be fair, just, and reasonable. This adjustment recognizes six months post test year data, which captures recent information.

[28] To the extent this adjustment should also apply to fuel inventories, it is so applied.

Payroll Taxes

The ALJ recommends that the Commission find that PUD's adjustment in the amount of ($104,334.34), based on PSO's effective rate of 6.955 percent is fair, just, and reasonable. The amounts of these adjustments represent a reduction of $1,604,468.70.

SPP Transmission Costs

The ALJ recommends that the Commission find that PSO shall not defer, as a regulatory asset or liability, the difference between actual expenses and the amount included in PSO's base rates. The ALJ also recommends that the Commission find that the following PUD adjustments to operating income related to PSO's base rate SPP expenses are fair, just, and reasonable: 1) Annualize Oklahoma TransCo. Prairie Wind and Transource Missouri Base Plan Funding Costs Not Recovered Through PSO's SPPTC tracker, in the amount of $1,183,801; 2) Annualize Oklahoma TransCo. Base Plan Funding Costs Per 2015 SPP Formula Rate Filing, in the amount of $1,653,610; 3) Annualize SPP Network Integration Transmission Service Costs, in the amount of $2,149,004; 4) Annualize SPP Administrative Fee, in the amount of $685,960; and 5) annualize SPP FERC Assessment Fee, in the amount of $37,901. The ALJ recommends that the Commission find the modification to the SPPTC tariff to limit annual adjustments should be approved.

Riders

The ALJ recommends that the Commission find PUD's recommendation to reverse the adjustments made to revenues (and costs) related to the System Reliability Rider is fair, just, and reasonable.

The ALJ recommends that the Commission find the overall use of riders shall be reviewed and that evaluation criteria shall be established for use in determining the need for additional riders. Riders shall be allowed only if they are used for costs that are outside of the utility's control, substantial, and unpredictable or volatile. In the future, the ALJ further recommends that a separate adjustment for the revenues and expenses collected pursuant to a rider approved by the Commission be addressed individually in PSO's Application Package, Schedule H.

The ALJ recommends that the Commission adopt the following findings: 1) that the Environmental Cost Recovery (ECR) shall not be approved and recovery of those costs shall remain in base rates; 2) that there shall be closure of the System Hardening Rider; 3) that language shall be added to the Southwest Power Pool Cost Tracker (SPPTC) that would require broader review if annual increase exceeds 50 percent; 4) that language shall be added to the Advanced Metering Infrastructure (AMI) to provide a date certain for closing the rider; and 5) that language shall be added to the Demand Side Management Cost Recovery Rider (DSMCRR) that would limit the accumulation of lost revenue recovery. The ALJ recommends that the above findings are fair, just, and reasonable.

Plant in Service

The ALJ recommends that the Commission find that PUD's proposed adjustments to update plant in service to the 6-month post test year balance at July 31, 2015, are fair, just, and reasonable. PUD's adjustment B-3 increases plant in service included in rate base by $9,557,979, unless exceptions apply herein.

Environmental Controls

The ALJ recommends that the Commission find that PUD's proposal to include $135,075,111 in environmental control investment incurred at 6 months post test year in rate base is fair, just, and reasonable.

Accumulated Depreciation

The ALJ recommends that the Commission find that PUD's proposal of an adjustment to update accumulated depreciation to the 6-month post test year balance at July 31, 2015 is fair, just, and reasonable. PUD's adjustment B-4 increases accumulated depreciation by $39,145,204, which is a decrease to rate base, unless exceptions apply herein.

Non-AMI (Automated Meter Infrastructure) Meters in Rate Base

The ALJ recommends that the Commission find that PUD's proposed adjustment to update regulatory assets to include Non-AMI Meters to the 6-month post test year balance at July 31, 2015 is fair, just, and reasonable. PUD's adjustment B-9 increases plant in service included in rate base by $18,262,961.

Cash Working Capital

The ALJ recommends that the Commission find that PUD's proposed adjustments to the cash working capital (CWC), which includes all of PUD's proposed changes to those accounts included within the cash working capital calculation, are fair, just, and reasonable. PUD agrees with the cash working capital methodology which excludes non-cash items such as depreciation, investment tax credit and common equity. PUD's adjustment will decrease cash working capital included in rate base by $186,040.

Accumulated Deferred Income Tax

The ALJ recommends that the Commission find that PUD's proposed adjustment to update accumulated deferred income tax to the 6-month post test year balance at July 31, 2015 is fair, just, and reasonable. PUD's adjustment will decrease accumulated deferred income tax included in rate base by ($39,145,204).

Prepaid Pension Asset

The ALJ recommends that the Commission find that the inclusion of $96,864,056 in prepaid pension assets in rate base as proposed by PSO and agreed to by PUD is fair, just, and reasonable.

Amortization Expense

The ALJ recommends that the Commission find that PUD's proposal to adjust the amortization expense to include amortization for Non-AMI meters in the amount of $1,749,592 is fair, just, and reasonable.

Factoring Expense

The ALJ recommends that the Commission find that PUD's proposal to adjust the factoring expense by ($224,029) to reflect PUD's revenue requirement is fair, just, and reasonable.

Ad Valorem Tax Expense

The ALJ recommends that the Commission find that PUD's proposal to adjust ad valorem tax expense by ($2,133,195) is fair, just, and reasonable.

Interest Synchronization

The ALJ recommends that the Commission find that PUD's proposed adjustment to the interest expense within the income tax calculation to reflect changes to the rate of return and rate base is fair, just, and reasonable. Interest synchronization is a method that provides an interest expense deduction for regulatory income tax purposes equal to the ratepayer's contribution to PSO for interest expense coverage. PUD's adjustment for interest synchronization will decrease the net income before income tax by $2,402,266.

Current Tax Expense

The ALJ recommends that the Commission find that PUD's proposal of an adjustment to current income taxes to reflect PUD's adjustments to the operating income statement, including the revenue deficiency, resulting in a net decrease to PSO's operating income of $7,513,020, is fair, just, and reasonable.

Cost of Service and Rate Design

The ALJ recommends that the Commission find that based on the results of PUD's inputs to PSO's COSS, retail customers would be allocated an increase of $58,132,537[29] excluding miscellaneous revenue, while the federal jurisdiction would be allocated a total of $1,235,810.

Regarding rate design, the ALJ recommends that the Commission find that there is a necessary increase in revenue requirement for the Company to continue maintaining safe and reliable service to consumers. The total increase is allocated to certain classes based on the results of a COSS. These results show the costs that each class of customers places on the system. PUD designed rates based on the necessary revenue allocations. The ALJ further recommends that prior to the next rate case, PSO will conduct a marginal cost study in order to

[29] The difference between this figure and PUD's Accounting Exhibit base rate revenue increase is due to a ($4,511,027) change in other revenues and PUD's proposal to include the System Reliability Rider in base rates.

develop a rate design that provides more accurate price signals to customers in order to promote more efficient use of electric energy and utility resources.

The ALJ recommends that the Commission find that PSO shall conduct a Minimum System study to identify and allocate customer-related costs for distribution assets before proposing a change to any class base service charge in future causes before this Commission, that the Commission shall adopt PUD's revenue distribution and rate design described in Mr. Schwartz's testimony, and that PSO shall add a separate line item on the consumer's bill that shows the breakdown of costs that can be attributed to managerial decisions of the Company and those that are due to outside action.

Distribution Costs Embedded in PSO's Fixed Monthly Charge

The ALJ reviewed the recommendation to require PSO to revert to a rate structure that recovers distribution, transmission and generation costs through variable kilowatt hour charges; and to direct PSO to redistribute any of its distribution-related charges that it has embedded in its fixed monthly fee and reallocate such costs back into its variable kilowatt hour charge as unnecessary to address, given that PSO's equal percentage rate increase methodology is not adopted.

Transmission Allocation

Within its cost of service study, PSO used a 12 coincident peak (12CP) method to allocate its transmission costs. OIEC objected to this change from PSO's historic use of 4CP to allocate these costs. PSO argues the Southwest Power Pool charges PSO for transmission services based on a 12CP allocator and, therefore, the use of a 12CP allocation is a reasonable basis to allocate such transmission costs to retail customers.

The ALJ finds that although PSO is a summer peaking system, it is appropriate to reflect the cost to use the transmission system during all twelve months of the year, rather than just during the summer months. The ALJ finds that the 12CP methodology seeks to ensure that customers who benefit from the use of the system in off peak months bear appropriate cost responsibility for the transmission system. The ALJ recommends the Commission accept PSO's use of the 12CP allocation of its transmission costs in its cost of service study.

AMI

While evaluating PSO's various riders, Staff identified the Advanced Metering Infrastructure (AMI) rider as one that should be modified. PUD Staff recommends the AMI Rider should be modified to include a sunset date at which time the rider would terminate. Staff identified in PSO's last rate case (Cause No. PUD 2013-217) that all of PSO's service territories are to have advanced meters installed by the end of the 3rd quarter of 2016, with any remaining meters to be installed in the 4th quarter of 2016. AARP, in its Statement of Position, identified that in PSO's last rate case that approved recovery of AMI costs through the AMI Rider, PSO represented that its AMI installation would conclude by the end of 2016, and therefore, AARP recommends the AMI Rider be amended to include a termination date of December 31, 2016.

The ALJ recommends the Commission adopt the amendment put forward by PUD Staff and strongly supported by AARP by requiring an amendment to PSO's AMI Rider to include an automatic termination date of December 31, 2016, which coincides with the date that PSO represented that its AMI installation would be completed. The AMI Rider is no longer necessary to collect costs from customers after the meters have been installed, so including a sunset provision within the terms of the tariff is appropriate and in the public interest.

Fuel Adjustment Clause Rider

In conjunction with its environmental compliance plan, PSO estimates that it may incur future costs of approximately $4,000,000 per year for certain air quality control system consumable costs that it would like to recover not through rates, but rather through a modification to its fuel recovery mechanism. These expenses are not for fuel, but are for materials consumed by certain air quality control systems that PSO plans to install in the future.

As with the recent OG&E case, Cause No. PUD 2014-229, AARP objected to the recovery of non-fuel costs within the fuel adjustment clause, and argued that such costs should be recovered through rates. AARP pointed out that while PSO may claim that these costs vary with the production of electricity, many utility costs may vary with the amount of electricity produced, but this does translate into recovery via the fuel adjustment clause.

The ALJ finds that PSO failed to identify any evidence that would support the need for recovery of consumable costs through the FAC as opposed to recovery through rates. The ALJ finds that PSO may seek recovery of such costs as may be incurred in the test year in a future rate case. The ALJ recommends the Commission not adopt PSO's request to modify its fuel adjustment clause to recover non-fuel consumable material costs and determine that recovery shall occur only through base rates at such time PSO actually incurs such costs.

Affiliate Costs

In its filing, PSO sought recovery of $62,630,559 of affiliate costs billed to it during the test year. Of this amount, $60,658,835 was billed by American Electric Power Service Corporation (AEPSC) and $1,971,724 was billed by other affiliates of PSO. (*See* PSO Witness Brian Frantz Direct Testimony at p. 4.)

Mr. Frantz explained how AEPSC is organized, the mission of the service company and how and why the services provided by AEPSC are necessary and promote efficiency by eliminating the need for each operating company to maintain staff and resources to perform the services separately. (*See* Frantz Direct at pp. 7-11.)

Mr. Frantz's Direct Testimony gave a specific explanation for the reason for a $2.9 million (or approximately 5 percent) increase in affiliate costs billed to PSO from AEPSC compared to PSO's last base rate case (Cause No. PUD 201300217). Namely, the movement of 60 transmission technical employees from operating companies to AEPSC because the employees were doing support work for many or all operating companies and should be service company employees. Additionally, he referenced a 3% average merit increase effective April 2015. (*See* Frantz Direct at p. 5.)

Mr. Frantz also described the levels of oversight and controls to ensure that costs billed to PSO are accurate, including transaction validation to ensure accuracy at point of entry, mechanical reviews to test the mechanics of the billing system, and monthly variance reviews to understand reasons for increases or decreases for AEPSC costs. He also discussed the management oversight, including budget and actual cost reviews, and monthly review and approval of the AEPSC bill by PSO and other affiliate companies. (*See* Frantz Direct at p. 12.)

His testimony provided a detailed description of the accounting and billing process, and also provided explanations of how AEPSC used benchmarking and market comparison data to ensure reasonableness of AEPSC charges. (*See* Frantz Direct at pp. 21-29 and at pp. 16-20.)

The exhibits to Mr. Frantz's Direct Testimony included breakdowns of AEPSC charges to PSO by functional organization, by work order and by activity; a detailed description of affiliate services provided to PSO by AEPSC; a description of AEPSC billing controls; a sample billing from AEPSC to PSO; and benchmarking study examples. (*See* Frantz Direct at Exhibits BJF-1, BJF-2, BJF-4, BJF-5, BJF-6.)

Further, other PSO Witnesses supported the services provided by AEPSC. PSO Witness Steve Baker explained in his Direct Testimony how AEPSC's Customer and Distribution Services (C&DS) organization provided specialized energy delivery support services and expertise across the AEP System. (*See* Baker Direct at pp. 6-9.) PSO Witness Gary Knight explained how AEPSC provides PSO generation with executive leadership, management direction, and staff support and he emphasized both PSO and AEPSC's focus on the safe, reliable and low-cost operation of PSO's generation fleet for the benefit of its customers, including through the sharing of best practices and lessons learned. (*See* Knight Direct at p. 3.)

Mr. Knight testified:

> AEPSC provides expertise on the operation and maintenance of PSO's fleet of power plants, as well as outage planning, unit dispatch management, and engineering and environmental support. AEPSC is responsible for providing these services for power plants across an 11-state area, and this vast knowledge of generation operation and maintenance is shared with PSO to help minimize the overall cost of generation and optimize plant reliability.
>
> 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. . . . [B]ecause AEPSC charges are spread over a number of 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.

(*See* Knight Direct at pp. 4-5.)

Mr. Knight also explained how the division of responsibility prevents any overlap or duplication of services between PSO and AEPSC generation employees. (*See* Knight Direct at p. 9.)

PSO Witness Charles Matthews explained how reliable electric service requires an adequate and well-maintained transmission system that meets applicable state and federal standards and how each of the services provided by AEP Transmission is necessary to operate a large transmission system like PSO's. (*See* Matthews Direct at p. 9.)

Witness Paul J. Wielgus for the Office of the Attorney General does not acknowledge all of the evidence PSO provides in support of the reasonableness of affiliate costs and relies on the Services Agreement between PSO and AEPSC asserting that the transactions are not conducted on an arm's length basis and recommending the removal of $2.9 million of AEPSC, which is the increase since PSO's last base rate case, Cause No. PUD 201300217. (*See* Wielgus Responsive Testimony at p.5 and p. 9.)

The ALJ credits all of the evidence that PSO has provided in its pre-filed and live testimony, work papers and exhibits supporting these costs, including Mr. Frantz's explanation for the increase in costs since the last base rate case provided above. The ALJ credits PSO testimony that AEPSC bills it charges at cost, to PSO and all AEP operating companies whether regulated or unregulated and derives no profit, while a third party contract would include some profit component. (*See* Frantz Rebuttal at p. 3.) The ALJ credits Mr. Frantz's Direct Testimony which details the internal controls, including properly designed and applied allocation factors, ensuring the cost of shared services are properly charged and management and operating company review of charges to understand their purposes and variances. The ALJ notes that while Mr. Wielgus saw no value in operating company review of service company billings, (*See* 12/15 Tr. at p. 24, ll. 7-14), he admitted he did not personally know what PSO's review entailed, (*See* 12/15 Tr. at p. 25, ll. 6-11), and the ALJ credits Mr. Frantz's testimony regarding the meaningfulness of the review allowing management to review the amounts and purposes of the charges. (*See* Frantz Direct at p. 12 and Rebuttal at p. 3.) With respect to Mr. Wielgus's concern that there is no review of the amount of usage of affiliate company services, (*See* Tr. 12/15 at p. 25, ll. 12-14), the ALJ credits Mr. Frantz's testimony that:

> PSO does have a say in the amount of Service Corporation charges that they're receiving each year through the budgeting process. They are involved in that process. It's a collaborative effort between the operating companies and the Service Corporation management. So they are involved in that process and they also review the monthly Service Corps bills and can ask questions about the reasonableness of those charges that they are getting. And, you know, if they

> send us questions. we'll resolve those issues. And maybe, if there is even, you know, a correction that needs to be made, we would correct that in a subsequent bill.

(*See* Frantz Tr. 12/15 at p. lw-184, ll 3-15.)

The ALJ also credits Mr. Frantz's testimony that involvement includes PSO senior management including its functional groups, such as transmission and generation. (*See* Tr. 12/15 at p. lw-187, ll. 3-11.)

The ALJ agrees with PSO that its system "fulfills the purposes of the affiliate rules by preventing subsidization of affiliates and protecting ratepayers from unreasonable and unfair charges." (*See* Frantz Rebuttal at p. 4, ll. 2-4.)

The ALJ finds, as the Commission historically has, such as in Order No. 564437 in Cause No. 200800144 at p. 27, that "PSO provided support for the affiliate costs paid by PSO and that no adjustment to these expenses is necessary."

Capitalized Incentives

PSO disagrees with the adjustment proposed by OIEC witness Mark Garrett to reduce rate base by $26,104,976 for capitalized incentives. (*See* Garrett Responsive, p. 15, lines 6-8.) OIEC was the only party to make an adjustment to reduce rate base by capitalized incentives.

Mr. Hamlett took issue with Mr. Garrett's statement found at page 15 of his Direct Testimony beginning at line 3 that his adjustment was consistent "with the Commission's prior treatment of PSO's incentive expense in its prior litigated cases, PUD 200600285 and PUD 200800144." Mr. Hamlett pointed out that Order No. 564437 issued in Cause No. PUD 200800144 stated "the Commission makes no finding in this Cause that PSO's incentive compensation costs are unreasonable and therefore declines to adopt the adjustment proposed by OIEC." (*See* Hamlett Rebuttal, p. 39, lines 17-19.) Further, capitalized incentives were not addressed in Cause PUD 200600285. (*See* Hamlett Rebuttal, p. 18-19.) Mr. Hamlett further pointed out that Mr. Garrett's total value of $49,426,251 covered the time period of 2000-2014. Capitalized incentive compensation from the years 2000 through January 2014, which was the 6-month post test year date used in the final order, Order No. 639314, issued in Cause No. PUD 201300217, PSO's last base rate case, have been included in rate base. (*See* Hamlett Rebuttal, p. 39, lines 20-23.)

No party contested that PSO's total compensation costs, including incentive compensation, were not reasonable or that the cost of assets were unreasonable. Mr. Garrett provides no support that PSO's total compensation or cost of assets are unreasonable. The ALJ recommends that the Commission make the same finding in this Cause as in Cause No. PUD 200800144 that PSO's incentive compensation costs are not unreasonable, and therefore, declines to adopt the adjustment proposed by OIEC.

Annual and Long-Term Incentive Compensation

The ALJ adopts Staff and AG's recommendation that an adjustment be made to remove the portion of the Annual Incentive Program costs related to financial performance measures. In many jurisdictions, including Oklahoma, the cost of incentive plans tied to financial performance measures generally are excluded for ratemaking purposes, for several reasons. (*See* Garrett Responsive Testimony, pp. 23-33). The evidence in this case established that the Company's incentive compensation is funded primarily based on the Company's financial performance (75% earnings per share). (*See* Garrett Responsive Testimony, p. 17).

The ALJ finds that AEP/PSO's incentive compensation plans are formal, written plans approved by senior management. In total, there are four annual incentive plans under which PSO and AEPSC employees may be compensated. These plans are described in the Direct Testimony and exhibits of PSO witness Andrew R. Carlin. In this application, PSO seeks to include $8.7 million in rates for annual incentive expense, [*sic*] based upon the Company's targeted payout incentive expense, according to the Company. (*See* Garrett Responsive Testimony, p. 15).

The Staff and AG witnesses proposed disallowing 50% of annual incentive compensation. OIEC recommended that the Company's proposed annual incentive costs be reduced by 75%, which was the funding percentage identified by Mr. Carlin as tied to financial performance.

The Staff and AG witnesses argued that the Company's and AEPSC's annual incentive compensation programs benefit ratepayers and shareholders equally and they should each share 50% of the costs. OIEC concluded that the Company's requested annual incentive costs are overwhelmingly weighted towards the Company, and as a result, OIEC recommended that 75% of incentive compensation be removed from the cost of service. (*See* Garrett Responsive Testimony, p. 31).

The Staff, AG, and OIEC all recommended that the entirety of PSO's test year long-term incentive compensation in the amount of $3,782,540 be disallowed. The witnesses testifying for such parties contended that all of the performance measures used in the long-term incentive program are based on achieving financial goals that appear only to benefit shareholders, and should not be paid by ratepayers.

PSO argued that the long-term incentive compensation for senior employees and the annual incentive payments should be recovered from ratepayers because no testimony was provided to indicate that the requested overall level of compensation is unreasonable. PSO further argued that providing a substantial component of compensation as incentive-based is normal in business today and considered to be good industry practice.

The ALJ finds that although there is no evidence to conclude PSO's and AEPSC's overall salary levels are excessive, the recommendation of the AG and Staff to disallow 50% of PSO's and AEPSC's annual incentive compensation should be adopted. Incentive compensation benefits both shareholders and ratepayers equally by encouraging the attainment of goals that provide good customer service and increase earnings of shareholders.

With regard to long-term incentive compensation, the ALJ finds that the recommendation of the Staff, AG, and OIEC to disallow 100% of long-term incentive compensation is reasonable, and should be adopted by the Commission. The performance measures that result in the payment of long-term incentive compensation are financial goals that benefit shareholders.

The result of the above disallowances reduces the recoverable expenses of PSO by $$3,782,540 for long-term incentive expense, which is 100% of the amount requested by PSO, and $4,369,947 for short term incentive expense, which is 50% of the 48,739,895 requested by PSO. (*See* Garrett Responsive Testimony, Ex. MG-2).

Supplemental Executive Retirement Plan (SERP)

The AG and OIEC recommend reductions to reflect the elimination of SERP expense from PSO's cost of service. SERP is AEP's non-qualified defined benefit retirement plan that provides benefits that cannot be provided under AEP's qualified defined benefit plans. According to PSO, SERP plans and other benefits are part of a market competitive benefits program for the utility industry and large employers in general.

The ALJ finds that it has consistently disallowed PSO's SERP costs in the past. The Commission disallowed 100% of PSO's SERP expense in PSO's 2006 rate case, Cause No. PUD 200600285, and in PSO's 2008 rate case, Cause No. PUD 200800144, the Commission again disallowed 100% of the Company's SERP expense.

The ALJ finds that SERP expenses are disallowed in other jurisdictions. (*See* Garrett Responsive Testimony, pp. 43-44). The Commission further finds that for rate-making purposes, utility shareholders should bear the additional costs associated with supplemental benefits to compensated executives. Therefore, the ALJ finds that the SERP expenses in the amount of $468,192, which is $156,433 of SERP costs at PSO and $311,759 of SERP costs at AEPSC, do not provide a benefit to PSO ratepayers, and therefore, PSO should be denied recovery of these costs in accordance with the recommendations of the AG and OIEC. (*See* Hearing Ex. 62).

IPP System Upgrade Credits

PSO made a reduction to rate base based upon the IPP Transmission Credits of $990,953, 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. No party opposed PSO's adjustment. (*See* Hamlett Direct, p. 33, lines 17-21.)

Vegetation Management Expenses

PUD made an adjustment to increase both expenses and revenues for the vegetation management expense moving from a rider to base rates. As discussed below under the SRR Rider section, PSO opposes PUD's adjustment. However, PSO stated that PUD's adjustment was accurate as to the total impact to customers, but did not provide a true reflection of how much base rates would change. When designing base rates, an addition of $21.7 million needs to be made to the cost-of-service. The impact of making this adjustment for designing rates is to increase base rates by $21.7 million while rider revenues will go down $21.7 million, resulting in no impact on customers. (*See* Hamlett Rebuttal, p. 63, lines 10-20.)

Northeastern 4 Non-Fuel O&M Costs

PSO seeks to reduce test year O&M expenses by approximately $2.1 million to account for the planned retirement of Northeastern Unit 4 and certain related offsetting adjustments. (*See* Norwood Responsive Testimony, pp. 47-49 and Ex. SN-15 to such testimony).

The ALJ finds that over the last three years, non-fuel O&M expenses for Northeastern Units 3 and 4 averaged approximately $26 million per year. (*See* Ex. SN-16 to OIEC witness Norwood's Responsive Testimony). PSO's proposed $2.1 million adjustment to O&M expenses resulting from the retirement of Northeastern Unit 4 is inconsistent with the estimated O&M savings associated with the retirement of Northeastern Unit 4 in 2016 as testified to by PSO in Cause No. PUD 201200054. Moreover, the ALJ finds that the workpapers provided by PSO supporting its proposed O&M adjustment could provide more information to demonstrate the reasonableness of the proposed adjustment.

The ALJ finds that O&M expenses should be reduced by $4.1 million for the planned retirement of Northeastern Unit 4, as recommended by OIEC witness Norwood in his Surrebuttal Testimony.

PSO proposes to increase its revenue requirement by $42,611,538, to reflect the Company's new depreciation rates from PSO's deprecation study. The recommendation of OIEC's recommendations regarding depreciation rates are set forth in the Responsive Testimony of Mr. Jacob Pous, who recommends a reduction in depreciation rates when applied to July 31, 2015, plant balances of $22,482,509.

While OIEC witness Pous did not address distribution plant depreciation rates, Staff witness David J. Garrett recommended an adjustment of $6.7 million to reduce the Company's proposed depreciation expense as it relates to distribution plant and an additional $461,000 to reduce the Company's proposed depreciation expense as it relates to general plant.

The ALJ finds that the differences in PSO's and Staff's proposed rates arise primarily from the following key issues: (1) premature retirement of Northeast Units 3 and 4 and related acceleration of capital recovery; (2) service life estimates for mass accounts, (3) net salvage estimates for mass property accounts, and (4) terminal net salvage estimates for life span accounts. The ALJ finds that in balancing the public interest between shareholders and customers, the capital recovery date for Northeast Units 3 and 4 should remain at 2040 for analytical purposes. PSO is planning on retiring Northeast Units 3 and 4 in 2026 and 2016 respectively, and the Depreciation Study reflects the recovery of Northeast Units 3 and 4 utilizing the retirement date of 2026. However, the existing probable retirement date adopted by the Commission for Northeast Units 3 and 4 was 2040, which represents the Units' actual, economic useful life. PSO is prematurely retiring these Units before the end of their useful lives, which accelerates capital recovery and increases the rate impact to customers by about $12 million. In order to balance the public interest in an equitable manner based on the current situation, the Company should not be allowed to accelerate the recovery of its capital investments in Northeast Units 3 and 4.

The net effect of Staff's adjustment to mass property accounts is a decrease of about $10 million to the annual accrual. The net effect of Staff's adjustment to mass property accounts is a decrease of about $10 million to the annual accrual. (*See* David J. Garrett Testimony Summary filed October 14, 2015, p. 5 adjusted by updated results for two distribution accounts, Exhibit DG-D14). The difference in PSO's and Staff's terminal net salvage rates arise primarily from two factors related to the estimated decommissioning costs: (1) removal of the escalation factor, and (2) removal of the contingency factor. PSO applied a 2.5% escalation factor to the estimated demolition costs, which adds about $77 million to the total capital recovery costs.

The ALJ adopts Staff witness Garrett's recommendation that the Commission should deny the proposed escalation of demolition costs in this case because (1) the escalated costs do not appear to be calculated in the same manner as other calculations; (2) the Company did not offer any testimony in support of the escalation factor; (3) an escalation factor that does not consider any improvements in technology or economic efficiencies likely overstates future costs; (4) it is inappropriate to apply an escalation factor to demolition costs that are likely overstated; (5) asking ratepayers to pay for future costs that may not occur, are not known and measurable changes within the meaning of 17 O.S. § 284; and (6) the Commission has not approved escalated demolition costs in previous cases. In its demolition cost study, S&L applied a 15% contingency factor to its cost estimates, and a negative 15% contingency factor to its scrap metal value estimates. The Company provides little justification for this contingency factor other than the plants might experience uncertainties and unplanned occurrences. This reasoning fails to consider the fact that certain occurrences could reduce estimated costs. Also, it is likely that S&L has overestimated the demolition cost.

The Company retained Mr. Spanos of Gannett Fleming to develop a depreciation study based on plant as of December 31, 2014 ("2014 Study"). The 2014 Study reflects an annual depreciation accrual of $139,877,572 or a $46,661,823 increase based on plant as of December 31, 2014. The ALJ finds that a 50% increase in depreciation expense due to a change in rates, not plant, should be considered extreme. Moreover, requested changes of this magnitude must be well explained, justified and supported. The ALJ finds that the requested increase lacks adequate explanation, and is not justified or supported.

The ALJ finds that the Company should provide a complete, detailed and fully documented depreciation study in support of its various life and net salvage parameters, by account, in its next rate case. The ALJ recognizes that the Company provided a large quantity of depreciation related material in this case. The critical items of information, assumptions, and supporting documents that identify how and why specific parameters were proposed should be submitted in a greater manner next rate case.

The ALJ further finds as follows:

- Northeastern Units 3 & 4 Life Span – The Company proposes a 2026 capital recovery date for the investment in Northeastern Units 3 & 4. The proposed 2026 date does not correspond to the retirement date set for Unit 4, as well it should not. Given the underlying basis for the change in expected life spans for the units, the more appropriate capital recovery date should be 2040. Recognition of a 2040 capital recovery date for Units 3 and 4, along with corresponding retirement date related impacts on interim retirements and net salvage, result in an approximate $10 million reduction in annual depreciation expense based on plant as of December 31, 2014.

- Production Plant Net Salvage – The Company proposes various negative net salvage values for its steam and other production generating facilities. These values are based in part on studies presented by Mr. Meehan of Sargent & Lundy, LLC ("S&L"). The S&L studies are updates of prior estimates for future demolition of the Company's generating units dating back to 2008. The results of the S&L studies were then expanded by Mr. Spanos for as many as 44 years into the future without discounting such values back to the present, and the estimated impact of interim net salvage was applied. Based on the elimination of contingencies and the escalation of estimated costs in to the future without discounting cost back to a net percent value, and a reduction in the level of estimated interim net salvage, depreciation expense is reduced by approximately $6 million based on plant as of December 31, 2014.

- Interim Retirements – The Company proposes a new method of calculating interim retirements for its plant. The Company's new method results in a significant increase in estimated interim retirements compared to the method and results that it proposed and the Commission approved in prior depreciation studies and rate cases. Since higher levels of estimated interim retirements results in a shorter remaining life, and thus higher depreciation expense, the Company's new methodology artificially increases depreciation expense. There are several problems associated with the Company's proposed new method. Relying on the Company's long established interim retirement methodology, as well as interim retirement ratios previously adopted by the Commission for the Company, results in an approximate $100,000 [sic] reduction in annual depreciation expense for plant as of December 31, 2014.

- Production Plant Interim Net Salvage – The Company proposes excessive negative net salvage levels for the higher level of interim retirements that it projects. Adjusting only the Company's proposed steam plant interim net salvage level to a more appropriate level results in a reduction in annual depreciation expense of $1,275,753 based on plant as of December 31, 2012.

- Mass Property Life Analysis – The Company relies on an actuarial analysis approach for estimating average service life ("ASL") and corresponding mortality dispersion pattern for mass property accounts. The Company's interpretation of the actuarial results are inappropriate and lead to artificially short ASLs for numerous accounts. Relying on more appropriate interpretation of actuarial results and information relating to life related improvements in operation and maintenance of the system, the ALJ adopts the transmission plant life recommendations of OIEC witness Mr. Pous and the distribution and general plant life recommendations of Staff witness Mr. Garrett.

- Mass Property Net Salvage – The Company's proposals for several mass property accounts result in excessive levels of negative net salvage. The Company's proposals fail to take into account specific impacts reflected in historical data that are not indicative of future net salvage expectations. Relying on more appropriate interpretations and analyses, the ALJ adopts the transmission and general plant net salvage recommendations of OIEC witness Mr. Pous and the distribution plant net salvage recommendations of Staff witness Mr. Garrett.

- Combined Impact – The combined impact of the various adjustments noted above are not simply the summation of each individual standalone adjustment. Certain adjustments are interactive. The combined impact of the various above noted issues results in a $30,576,729 reduction in annual depreciation expense based on plant as of December 31, 2014, as set forth on the applicable portions of Exhibit JP-1 and Exhibit DG-D-1 through DG-D-4 and DG-G-14.

Recovery of Northeastern Unit 4 Plant Costs

PSO proposed to retire the 460 MW Northeastern Unit 4 coal plant in the middle of its useful life, but plans to continue to include both a "return on" and a "return of" the plant costs in rates. The Company plans to accelerate the "recovery of" the plant costs over a 10-year period rather than the 25-year period now in place. There are three cost recovery issues associated with this plant closure:

1. PSO's plan to continue to include the un-depreciated balance of this plant in rate base, enabling the Company to continue to earn a full profit "return on" the abandoned plant for its shareholders;

2. PSO's plan to continue to depreciate the balance of this plant into rates so that shareholders will receive a full "return of" the abandoned plant costs; and

3. PSO's plan to shorten the depreciation recovery term to a 10-year period.

The ALJ finds that the net un-depreciated plant balance for Northeastern Units 4 at July 31, 2015, was $79.2 million. (*See* Garrett Responsive Testimony, p. 48, PSO Response to OIEC 5-25). The annual rate base "return on" this amount would be approximately $7.4 million. A 10-year accelerated depreciation of the Unit 3 and Unit 4 assets results in additional annual depreciation expense of about $13 million.

The ALJ finds that while Unit 4 was actually in service during the test year and during the six-month period after test year end, Unit 4 will be taken out of service in April 2016 to coincide with the in-service dates of the $221 million of new plant investments at Northeastern 3 and other gas plants to meet PSO's proposed ECP. PSO is seeking recovery of its ECP investment either through extending the rate base in this case out to April 2016 or through rider treatment for these costs starting in April 2016. Under either approach, the stranded Northeastern Unit 4 costs should be deducted from the rate base that includes these new ECP assets that replace Unit 4 under any scenario, whether (1) the rate base in this case is extended to April 2016, (2) a rider is established in April 2016, or (3) the assets are included in the rate base of a subsequent rate case the Company files after the assets go into service, in the event both of the scenarios (1) and (2) proposed by PSO are rejected by the Commission. The point is, when the new ECP assets go into service, Unit 4 will be taken out of service and at that point Unit 4 should be taken out of rate base and a return on the remaining balance should no longer be included in rates. More precisely, when the new ECP assets are included in rates, Unit 4 should be taken out of rates, or at least the return on the investment in Unit 4 should be taken out of rates.

The ALJ finds that PSO may not include in rate base the costs of the Northeastern No. 4 Unit. PSO is not entitled to a return of and return on such costs. Assets that are used and useful for providing service to the public may be included in rate base. *See 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. After the Northeastern Unit No. 4 is retired, it will not be providing service to the public and will no longer be used or useful.

The ALJ adopts the recommendation of OIEC witness Garrett that the return on Unit 4 be suspended when the assets are no longer *used and useful* for providing service. The Commission finds that the return on the Unit 4 balance should end when the return on the new ECP assets begins, whether the return on the new ECP assets begins through (1) extending the rate base in this case out to April 2016, (2) implementing a rider to begin in April 2016 or (3) filing a subsequent rate case after the assets go into service. Under each of these scenarios, the rate base used to calculate the revenue requirement for the new ECP assets should be reduced by the remaining balance of the Unit 4 assets. This treatment would eliminate the *return on* the assets no longer used and useful for utility service but would allow the continued *return of* those assets through depreciation recoveries. The impact of this adjustment is $7,429,535, as shown at Exhibit MG 2.8.

Revenue Normalization

Witness for the DOD and AG both recommended adjustments to increase PSO's test year adjusted base rate revenues to reflect updated customer accounts as of July 31, 2015, the 6-month post-test year period. (*See* Farrar Responsive, p. 7, lines 5-20; *See* Morgan Responsive, p. 13, lines 9-25.)

Mr. Morgan recognized that his approach was not as precise as the approached used by PSO. (*See* Morgan Responsive, p. 13, line 23.) Both the AG and DOD adjusted base rate revenues to reflect updated customer accounts as of July 31, 2015.

PSO did not agree with these adjustments because PSO's test-year adjusted and annualized base rate revenues were the result of a comprehensive analysis reflecting the test-year ending level of customers, weather adjustments, rate changes, and other specific customer billing adjustments. (*See* Aaron Rebuttal, p. 15, lines 2-4.) PSO cited Order No. 564437, issued in Cause No. PUD 200800144, where at pages 3 and 4, the Commission stated that "adjustments to expenses and revenues, which fluctuate based upon the number of customers, the weather, the time of year, etc. should be closely reviewed to make certain that normalization methodology captures the best possible estimate of future expenses and revenues. The Commission finds that simply "updating" expenses and revenues to the 6-month post-test year period, without an analysis regarding the reasons for the change since test-year end, has the potential for creating a new test year that has incomplete and/or mismatched information within it." (*See* Aaron Rebuttal, p. 15, lines 7-14.)

The ALJ recommends the Commission not adopt the adjustments by DOD and AG as a proper adjustment to annualize the revenues that occurred in the 6-month post-test year period would consider the weather adjustments, rate changes, and other specific customer billing adjustments and not only one component, the number of customers, as was done by DOD and the AG.

SPP IM Revenues

OIEC witness Norwood recommended that PSO's FCA Rider be modified to exclude the net revenues or costs for SPP IM services (which included regulation, spinning reserves and supplemental reserves services) from the amount that would be included in off-system sales (OSS) margin sharing under the FCA Rider. (*See* Norwood 10/3/15 Responsive, p. 10, lines 8-9.) No other party to the proceeding made a recommendation regarding changes to OSS margins.

PSO witness Hakimi testified that any net revenues from the sale of ancillary services is booked in FERC account 447, which is the same account used for booking net revenue from energy sales, and is therefore consistent with PSO's FCA Rider. (*See* Hakimi Rebuttal, p. 8, lines 4-6.) Mr. Hakimi further testified that Mr. Norwood's recommendation to remove accounts 4470326, 4470328, 4470330, and 4470332 are not ancillary service sales accounts. The revenues and charges in those accounts reflect other revenue [*sic*] or costs incurred in making energy sales in the market. Mr. Norwood did not provide any rationale to explain why those accounts should be excluded. (*See* Hakimi Rebuttal, p. 8, lines 12-17.) Without these accounts, the margin from energy sales would be incomplete and not reflect the actual margins when all the variable components of such sales are included. (*See* Hakimi Rebuttal, p. 8, lines 18-10.)

Mr. Hakimi testified that AEPSC, on behalf of PSO, optimizes the value of PSO's generation by participating in both the SPP IM Energy markets and the operating reserve markets. The optimization strategy extended beyond PSO's participation in the SPP IM day-ahead and real-time markets. (*See* Hakimi Rebuttal, p. 5, lines 14-17.) Mr. Hakimi's testimony described ways in which PSO provided additional value to its customers by using an extended look-ahead to form its day-ahead offers. For example, during a low demand period, such as often occurs over weekends, the variable cost of a unit may exceed the cost of the marginal unit SPP's security constrained economic dispatch model identifies in relation to the Day-Head market over a longer period of time, this unit would not be selected to run and would instead be shut down. However, as one extends the frame under which the unit's economics in relation to the market are evaluated, then the decision to run or shut down the unit over the weekend becomes much more complex. To properly evaluate the unit economics requires information such as unit shut down and start-up cost, forecasted demand, not just for the next day, but for many days in the future, forecast in clearing prices, potential performance issues for other units within PSO's portfolio, and estimates of bilateral and over-the-counter energy purchase and sale opportunities over the same time frame. This process occurs outside the SPP IM responsibilities of PSO, and relies on the combined expertise and coordination of many groups within the AEPSC for its success. (*See* Hakimi Rebuttal, p. 6, lines 19 p. 7 line 9.)

Mr. Hakimi's testimony demonstrated that the sale of ancillary services is an integral part of PSO's optimization strategy in the market.

Mr. Hakimi further testified that, if Mr. Norwood's recommendation was adopted, it would result in artificial separation. [*sic*] could provide outcomes where the Company shares in the losses for the an [*sic*] energy account part of the OSS transaction, but would not receive a share of the positive revenue from other parts of the transaction recorded in the accounts that Mr. Norwood recommends for exclusion from OSS margin sharing. (*See* Hakimi Rebuttal, p. 9, lines 5-11.)

The ALJ finds that OSS energy margins and operating reserve revenues are closely related and are part of the same optimization process that looks at the combined revenues of these services in the SPP IM. The ALJ agrees with PSO that OIEC's proposal to remove the net ancillary services and certain other energy sales related revenues from the calculation of OSS margins would result in a distorted calculation of OSS margins. Therefore, the ALJ recommends that the Commission not adopt OIEC's proposed changes to the calculation of OSS margins in PSO's FAC.

Revenue Requirement

The above findings and recommendations cannot be given effect by revisions to the Company's initial case until each adjustment recommended above is included as an input to PSO's cost of service model. This is a necessary step in order to calculate an accurate revenue requirement and then to proceed to the task of rate design. Accordingly, the ALJ recommends that within five (5) business days after the date of the ALJ Report PSO should provide to the ALJ and each party a revised cost of service that incorporates each of the adjustments and recommendations set out above.

Respectfully Submitted, this 31st day of May, 2016.

Jacqueline T. Miller

Jacqueline T. Miller
Administrative Law Judge