BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. PUD 201300217

HEARING: July 21, 2014, and July 22, 2014, at 8:30 a.m. in Courtroom 301
2101 N. Lincoln Blvd., Oklahoma City, Oklahoma 73105
Before Jacqueline T. Miller, Administrative Law Judge

APPEARANCES: Jack P. Fite, Joann T. Stevenson, Rhonda C. Ryan and Gerardo Noel Huerta, Attorneys *representing* Public Service Company of Oklahoma;
Judith L. Johnson, Senior Attorney, and Elizabeth A. P. Cates, Deputy General Counsel, *representing* Public Utility Division, Oklahoma Corporation Commission;
William L. Humes, Nicole A. King, Jerry J. Sanger, and Tessa L. Hager, Assistant Attorneys General, *representing* the Office of the Attorney General, State of Oklahoma;
Thomas P. Schroedter, D. Kenyon Williams, 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.;
Deborah R. Thompson, Attorney *representing* AARP;
Don M. Powers and G. Kay Powers, Attorneys, *representing* Intervenor Joe Esposito;

REPORT AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE

The filing of this cause by Public Service Company of Oklahoma ("PSO") was made to satisfy the requirement contained in a Joint Stipulation and Settlement Agreement ("Joint Stipulation") approved by the Oklahoma Corporation Commission ("Commission") by Order No. 591185, issued in Cause No. PUD 201100106, wherein the Stipulating Parties agreed that PSO would file a base rate case that included the requirements of OAC 165:70-1-1 et seq., no later than twenty-six (26) months from the date of Order No. 591185 (November 18, 2012).

Summary

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

I. Procedural History

On November 26, 2013, PSO filed a Notice of Intent pursuant to OAC 165:70-3-7. In that Notice of Intent, PSO stated that it planned to file testimony and exhibits that would fulfill the requirements of Paragraphs 6 and 7 found on Page 9 of Order No. 591185. Further, PSO stated that it would be filing supporting documentation in connection with a request for a general rate change. PSO stated that to be in compliance with Order No. 591185, the filing would need to be made before January 18, 2014.

On December 2, 2013, an Entry of Appearance ("EOA") was filed by the Attorney General ("AG").

On January 2, 2014, an EOA was filed by AARP.

On January 7, 2014, an EOA was filed by the Oklahoma Industrial Energy Consumers ("OIEC").

On January 14, 2014, the Quality of Service Coalition ("Coalition") filed an EOA. PSO's Application, the Minimum Filing Requirements and Testimony were filed on January 17, 2014.

On January 30, 2014, PSO filed a Motion to Establish Procedural Schedule ("Motion") and set the Motion for hearing on February 6, 2014. The Motion was continued by agreement of the parties to February 13, 2014 and heard by the Administrative Law Judge ("ALJ") on that date. The dates as presented on February 13, 2014, were agreed to by all parties. The following day, February 14, 2014, the ALJ proposed an alternative procedural schedule in order to comply with the 180 day period. The parties indicated that their proposed procedural schedule had been accomplished through great effort and could not be altered. PSO then advised the ALJ that it waived the 180 day period pursuant to 17 O.S. §152 and that the Company would not implement interim rates until November or December 2014, if necessary. The ALJ then recommended the agreed procedural schedule of the parties.

On January 31, 2014, Wal-Mart Stores East, LP, and Sam's East, Inc., (collectively "Wal-Mart") filed an EOA. On February 6, 2014, the Commission's Public Utility Division ("PUD") filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements stating PSO was in substantial compliance with the Minimum Filing Requirements set forth in OAC 165:70 for Class A or B utilities.

Public Comment was filed on February 18, 2014.

On February 27, 2014, this Commission issued an Order Establishing Procedural Schedule (Order No. 622061) which, among other things, set a hearing on the merits to begin June 25, 2014.

On March 4, 2014, Intervenor Mr. Joe Esposito filed an EOA, and filed an amended EOA on March 7, 2014.

On March 17, 2014, AARP filed *its Motion Objecting to PSO's First Set of Data* Requests. The Motion was set for March 27, 2014, and was withdrawn on that date. On March 21, 2014 AARP filed its Objection to PSO's Classification of Certain Documents as Confidential ("Objection"). The Objection was set for April 3, 2014, but was advanced to March 27, 2014. At that time, the Objection had been settled and the ALJ recommended the settlement.

On March 24, 2014, PUD, AG, Wal-Mart, OIEC, AARP, Mr. Esposito and Coalition filed Major Issues Lists.

On March 26, 2014, PSO filed its Motion to Determine Notice. The Motion was set for April 3, 2014. On April 9, 2014, PSO filed an Amended Motion to Determine Notice, which was set for hearing on April 10, 2014, and was recommended on that date. Also on April 10, 2014, PSO filed its Exhibit "A" to the Amended Motion to Determine Notice.

Public Comment was filed on April 3, 2014.

On April 22, 2014, this Commission issued two Orders dealing with discovery disputes that had been settled between PSO and AARP. Order No. 624237 was an Order on AARP's Motion Objecting to PSO's First Data Requests to AARP and Order No. 624238 was an Order on AARP's Objection to PSO's Classification of Certain Documents as Confidential .

On April 23, 2014, Responsive Testimony was filed on behalf of PUD, AARP, and the AG. OIEC and Wal-Mart filed the Direct Testimonies of David C. Parcell and Jacob Pous. PUD also filed its Accounting Exhibit.

On April 24, 2014, PSO filed its Motion to Associate Counsel, which was set for hearing on May 8, 2014, and was recommended on that date.

On May 1, 2014, this Commission issued an Order Regarding Notice (Order No. 624719) setting forth the Notice to be published by PSO once each week for two consecutive weeks at least fifteen (15) days prior to the hearing.

On May 7, 2014, Rate Design Testimony was filed on behalf of the AG, Responsive Testimony was filed on behalf of PUD, Wal-Mart and OIEC, and PUD also filed Cost of Service Testimony.

On May 12, 2014, AARP filed its Statement of Position.

On May 13, 2014, the late filed Statement of Position of Coalition was filed and on May 14, 2014, Coalition filed its Motion to Accept Statement of Position Out of Time. The Motion was set for hearing on May 22, 2014, but was advanced to May 14, 2014 and was recommended at that time.

On May 20, 2014, this Commission issued an Order Granting Motion to Associate Counsel (Order No. 625647) wherein Rhonda C. Ryan and Gerardo Noel Huerta, members of the

Texas Bar Association, were granted permission to participate in this docket pursuant to the requirements of 5 O.S. Ch. 1.App. 1, Art II. Also on May 23, 2014, PUD filed the Responsive Testimony Errata of Luis F. Saenz.

On May 27, 2014, this Commission issued an Order Granting Motion to Accept the Statement of Position Filed Out of Time by Quality of Service Coalition (Order No. 625944). The AG also filed the Errata Testimony of Edwin C. Farrar on that same date.

On May 29, 2014, Rebuttal Testimony was filed on behalf of PSO, OIEC and AARP.

Public Comment was filed on May 30, 2014.

On June 5, 2014, AARP filed a Motion to Strike Rebuttal Testimony of PSO Witness Derek S. Lewellen or, in the Alternative, Suspend Procedural Schedule Set Forth in Order No. 622061, as well as the Affidavit of Barbara R. Alexander.

On June 12, 2014, AARP's Motion to Strike was heard before the ALJ. At that time, the ALJ denied the request to strike the rebuttal testimony of PSO witness Derek S. Lewellen, but granted part of the Motion by suspending a portion of the procedural schedule relating to the Advanced Meter Infrastructure ("AMI") portions of Mr. Lewellen's rebuttal testimony. A final determination of dates for hearing on AMI issues was continued by agreement of the parties to the pre-hearing conference to be held on June 19, 2014.

On June 17, 2014, Surrebuttal Testimony Issues were filed on behalf of OIEC, AARP, and the AG. On June 17, 2014, the Joint Stipulation and Settlement Agreement was filed.

On June 18, 2014, the AG filed its Exhibit List, as well as the Summary of the Responsive and Rate Design Testimony of Edwin C. Farrar. Proofs of Publication were also filed on that date.

On June 19, 2014, AARP filed the AARP Testimony Summaries of the Responsive and Rebuttal Testimony of Barbara R. Alexander Filed on April 23, 2014 and May 29, 2014, Respectively, and its exhibit list. At the pre-hearing conference on June 19, 2014, parties requested additional time to propose a schedule so the pre-hearing conference was therefore continued by agreement of the parties until June 25, 2014, at 10:30 a.m.

On June 20, 2014, the signature page of the Joint Stipulation Agreement of Wal-Mart was filed.

Public Comment was filed on June 24, 2014.

On June 25, 2014, an additional pre-hearing conference was held and the parties agreed to a new schedule which included a hearing on the merits to begin at 8:30 a.m. on July 21, 2014. OIEC and PUD filed their Exhibit Lists on that same date. Also on June 25, 2014, PSO filed the Affidavit of JoElla Ford, and the AG filed the EOA for Ms. Tessa L. Hager. OIEC also filed Testimony Summaries for David Parcell, Jacob Pous and Mark Garrett.

Public Comment was filed on June 25 and 27, 2014.

On June 30, 2014, Supplemental Testimony in support of the Joint Stipulation and Settlement Agreement were filed on behalf of PSO and PUD.

On July 3, 2014, AARP filed the Supplemental Responsive Testimony of Barbara R. Alexander.

Public Comment was filed on July 8, 2014.

On July 9, 2014, the Second Joint Stipulation and Settlement Agreement was filed and the Joint Stipulation Agreement signature page for the AG to the First Joint Stipulation and Settlement Agreement was filed.

On July 10, 2014, Summaries of Direct, Rebuttal, Supplemental and Responsive Testimonies were filed by all parties of record who filed testimony, as well as the Exhibit List of Wal-Mart and the Witness and Exhibit List of PSO. On that same date, OIEC's signature page to the Second Joint Stipulation and Settlement Agreement was filed, along with a letter from the AG's Office stating that the Joint Stipulation and Settlement Agreement Signature Page of the Oklahoma Attorney General, filed with the Commission on July 9, 2014, was inadvertently filed without the signature page. The July 10, 2014, filing contained the signature page. Also on July 10, 2014, the AG filed the Supplemental Testimony in Support of the Second Joint Stipulation and Settlement Agreement of Edwin C. Farrar. PUD also filed its Witness List.

The Commission issued Order Regarding Procedural Schedule Order No. 622061 (Order No. 627830) on July 15, 2014. The new Procedural Schedule set forth the Order and presentation of witnesses and cross examination, as well as the issues to be addressed and additional procedural requirements. The Commission also issued Order On AARP's Motion to Strike the Rebuttal Testimony of PSO Witness Derek S. Lewellen, Or, In the Alternative, Suspend Procedural Schedule Set Forth In Order No. 622061 (Order No. 627829) on July 15, 2014. On that same date, Public Comment was filed.

On July 15, 2014, Supplemental Rebuttal Testimony was filed on behalf of PSO. On July 16, 2014, PSO filed the Summary of the Supplemental Rebuttal Testimony of Derek S. Lewellen and the Supplemental Rebuttal Testimony Summary of David P. Sartin, and the AG filed the Summary of the Supplemental Testimony in Support of the Second Joint Stipulation and Settlement Agreement of Edwin C. Farrar.

On July 17, 2014, a Supplemental Exhibit List was filed on behalf of AARP, as well as AARP's Objections to portions of PSO's exhibit list, AARP's Testimony Summary of the Supplemental Responsive Testimony of Barbara R. Alexander filed on July 3, 2014 and the AARP Supplemental Surrebuttal Testimony Issues.

Public Comment was filed on July 18, 2014.

On July 21, 2014, the hearing on the merits was held beginning at 8:30 a.m. and was continued to July 22, 2014. On that date, the matter was taken under advisement by the ALJ.

Public Comment was filed on July 24, 2014 and August 8, 2014.

On August 22, 2014, PSO filed its Proposed Report and Recommendations of the Administrative Law Judge, AARP filed its Proposed Findings of Fact and Conclusions of Law and PUD filed its Proposed Final Order Approving Joint Stipulation and Settlement Agreement.

Public Comment was filed on September 9, 2014.

On September 25, 2014, the AG filed the EOA of Mr. Erick W. Harris.

II. Summary of Evidence

Summary of Direct and Rebuttal Testimony of Donald A. Murry, Ph.D.

Dr. Donald A. Murry, an Economist with C. H. Guernsey & Company, testified on behalf of Public Service Company of Oklahoma (PSO). Dr. Murry is also a Professor Emeritus of Economics on the faculty of the University of Oklahoma.

Dr. Murry earned a B.S. in Business Administration and an M.A. and a Ph.D. in Economics from the University of Missouri - Columbia.

Dr. Murry testified that he first considered the current and near-term economic conditions and financial markets, as this is the environment for the determination of PSO's ROE. Analytically, he applied familiar market measures of the cost of common equity and reviewed the recent and projected earnings of electric utilities. Based on this analysis, he recommended an allowed return on common equity in the range of 10.5 to 11.0 percent for PSO in this proceeding. Based on this recommended return on common equity, he recommended a corresponding return on total capital in the range of 7.94 percent to 8.18 percent for PSO.

According to Dr. Murry, in determining this recommended return, he studied the current and near-term credit and equities markets, the associated current financial statistics, current and forecasted electric utilities' common stock earnings, and market-based measures of returns on common stock.

He adopted the proposed capital structure of 51.313 percent long-term debt and 48.687 percent common stock equity as appropriate for PSO in this proceeding. He also adopted the weighted average cost of long-term debt of 5.51 percent.

Dr. Murry testified that an important conclusion during this analysis was the importance of the slow economic recovery from the recession, the Federal Reserve's maintenance of extremely low interest rates and emerging concerns about prospective increased inflation rates. Equity investors in electric utilities are likely to view long-term debt securities as alternative investments, but the risk premiums, as well as expected returns, are likely to be distinctively different between utility equities and the debt instruments. The differentials in the risk premiums between common equity and debt securities in the current markets appear analytically important. The recent equity markets have been relatively volatile, and this also is important to investors.

Because PSO is not publicly traded, Dr. Murry testified he reviewed the financial information available for American Electric Power Company (AEP), the parent company of PSO. AEP's common stock market value reflects many of the risks that investors would associate with PSO, should that common equity be publicly traded. Although limited to data from the volatile financial markets, he applied the Discounted Cash Flow (DCF) method to estimate the cost of common equity of the Company. He also applied a Capital Asset Pricing Model (CAPM) analysis. In the case of these market-based methods, interpretation of the results is important because of the impact of Federal Reserve policies. He applied these methods to the common stock of AEP and to each of a group of comparable electric utilities as relevant market-based measures of the cost of common equity of PSO.

According to Dr. Murry, the DCF and CAPM measures of the cost of common equity for electric utilities are wide ranging. Because of the recent recession and the slow recovery, investors are not likely to be viewing the near-term markets as represented by historical data. The most relevant DCF measures of the cost of common equity are those based on expected returns. Although requiring interpretation due to the impact of volatile markets on the relevant data, the most applicable DCF results were 9.14 percent for AEP. Reflecting the recent market volatility, the DCF range of the comparable companies was from 7.01 percent to 11.99 percent. Because of the marginal cost nature of the DCF result for the purposes of setting an allowed return, these estimates are low, but they are a basis, or a starting point, for determining an allowed return.

Dr. Murry further testified that the CAPM calculations are directly affected by the current monetary policies of the Federal Reserve and, unless recognized, this renders them potentially flawed. At a minimum, they require analysts to interpret results while remaining mindful of the impact these monetary policies have on the data used in the analysis. The most relevant CAPM results are based on forecasted market returns. The CAPM common equity estimates were 11.30 percent for AEP and an average of 10.95 percent for the comparable electric utilities.

To confirm that his recommended 10.5 to 11.0 percent recommended allowed return on common stock would be sufficient to attract and maintain investment funds, he compared the After-Tax Interest Coverage (ATIC) at his recommended allowed return level to the current coverages for the comparable electric utilities. This comparison would also help assure that his recommended allowed ROE was not higher than necessary. From this analysis, the AEP ATIC at the low end of his recommended range would be 2.81 times. This coverage is within the range of the ATICs for the comparable companies and indicates that his recommendation is adequate to attract and maintain capital in the current and near-term future markets, but it is not higher than necessary.

Dr. Murry's rebuttal testimony noted that despite the recognized slow economic recovery and the significance of the Federal Reserve's monetary policy in maintaining very low short-term interest rates and large levels of liquidity in the economy, none of these witnesses adequately addressed the impact on utility common equity investors. Dr. Murry attempted to update and clarify the significance of the current and near term economic environment. Second, Dr. Knapp and Mr. Parcell selected an inappropriate company, PG&E, for analytical comparison with PSO. Because of the circumstances facing PG&E and the associated cost of capital implications, this led to using low-biased calculations in their cost of common equity analyses. Third, according to Dr. Murry, none of these witnesses effectively measured or applied tests of the adequacy of their recommended returns. If they had, they would have recognized that their recommendations were extremely low for PSO in the current market. At minimum, Dr. Knapp and Mr. Parcell could have compared measures of earnings adequacy to similar measures for the companies that they had selected as comparable to PSO. Additionally, he made some technical comments regarding the methods and calculations used by each of the cost of capital witnesses in developing their direct testimonies. Finally, he reviewed Mr. Garrett's comments in his Direct Testimony concerning PSO's rate riders and their impact on investors' perceived risk. According to Dr. Murry, Mr. Garrett's analysis of rate riders and investor risks was seriously flawed, and Mr. Garrett based his cost of capital policy recommendation upon it.

<u>Summary of Direct and Rebuttal Testimonies of Steven F. Baker</u>

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 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 discussed the services provided to PSO by American Electric Power Service Corporation (AEPSC), he supported the distribution system investments made since PSO's last rate case, and discussed the July 2013 storm that affected PSO's service territory, as well as two December 2013 ice storms.

Mr. Baker testified that during the test year, PSO distribution has incurred approximately \$44.9 million in O&M expenses, including AEPSC charges. Since the last base [*sic*] case, PSO distribution has made approximately \$302.2 million in capital investments in the distribution system. These investments were necessary to complete customer demands for new service, capacity increases, maintenance [*sic*] activities and improve the reliability of PSO's distribution system. In addition, PSO safely and effectively restored service to approximately 131,000 customers affected by a major weather event that occurred on July 24, 2013. This storm caused extensive damage to PSO's distribution facilities, the cost of which the Company is seeking to recover over a four-year amortization period in this proceeding.

Mr. Baker testified that the purpose of his rebuttal testimony was to respond to various parties' statements and recommendations to alter or entirely eliminate PSO's System Reliability Rider (SRR, formerly known as the Reliability Vegetation/Undergrounding Rider, or RVU). He explained why the recommendations were unnecessary and could possibly hinder PSO's flexibility to respond to system needs on a year-by-year basis, thus jeopardizing overall system reliability.

Mr. Baker explained that in Cause No. PUD 201300202, on December 31, 2013, less than six months ago, the Commission issued an order approving PSO's request to broaden the scope of the rider to include cost recovery for system hardening and grid resiliency efforts, recognizing the need to allow PSO the flexibility to address its system needs through multiple methods, while retaining an emphasis on vegetation management. As a result, in its current form, the SRR provides for the recovery of $23.685 million of vegetation management and system hardening and grid resiliency O&M costs. This amount is incremental to the costs currently included in base rates for vegetation management ($6.285 million). The rider also allows for recovery of $7.7 million of carrying costs associated with overhead to undergrounding and system hardening and grid resiliency capital costs. The AG, OIEC, and PUD were parties to Cause No. PUD 201300202.

According to Mr. Baker, PUD filed testimony supporting expansion of the SRR, recognizing the need for flexibility in maintaining the reliability of the system. Notably, PUD witness Amy Taylor concluded that the "...PUD believes that PSO's effort to create a more comprehensive and flexible program is in the public interest because it would strengthen total grid reliability without having any known detrimental effect." Ms. Taylor further detailed how PSO committed that maintaining its four-year vegetation management cycle would be its top reliability priority. The AG filed a Statement of Position also supporting the request and recognizing the benefit of flexibility, specifically citing Ms. Taylor's above-referenced testimony regarding flexibility. OIEC also filed a Statement of Position taking no position in the case. No party expressed concern with the amount of vegetation management costs or the need to significantly alter or terminate the rider.

Mr. Baker did not support Mr. Thompson's recommendation to move a fixed level of vegetation management expense into base rates.

According to Mr. Baker, with the rider as it exists today, PSO's customers receive significant benefits from its reliability program, while the Commission and the PUD receive cost and planning information on a quarterly basis to ensure that these costs are both reasonably and prudently incurred. Narrowing the rider to recover only system hardening costs and placing a fixed level of vegetation management expense into base rates could limit PSO's ability to maintain its four-year vegetation management cycle. Further, it seems to conflict with the carefully considered position taken by PUD in regard to expanding the rider but preserving the focus on vegetation management.

Also, according to Mr. Baker, the amounts proposed by Mr. Thompson (and Mr. Farrar) for vegetation management are less than what PSO has been spending on its vegetation management program for the last several years.

Mr. Baker concluded by testifying that the Final Order in Cause No. PUD 201300202 supported PSO's need for flexibility and agreed with Ms. Taylor's previously cited recommendation to approve PSO's request to include storm hardening and grid resiliency activities as part of the rider, while retaining a focus on vegetation management. No party has provided any reason as to why circumstances have changed since the Commission issued the order granting expansion of the rider less than six months ago. Further, no party has provided any evidence as to how removing the vegetation management component from the rider will positively impact customers. Rather, by retaining the vegetation management rider and costs in its entirety, customers will only pay for those vegetation management costs that are actually incurred. This also ensures that PSO has the flexibility to address system needs year-to-year to maintain the system reliability that customers have come to know since the inception of the SRR.

Summary of the Direct Testimony of 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. Matthews' 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 $69 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 $51.99 million.

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

<u>Summary of the Rebuttal Testimony of A. Naim Hakimi</u>

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).

Mr. Hakimi's rebuttal testimony responds to recommendations made by Oklahoma Corporation Commission (OCC or Commission) Public Utility Division (PUD) witness Sharon Fisher's and Oklahoma Industrial Energy Consumers (OIEC) witness Mark Garrett's recommendations made to modify the longstanding Commission approved Off-System Sales (OSS) margin sharing arrangement for PSO.

Mr. Hakimi's testimony also addressed issues raised by Mr. Garrett regarding a change to the AEP West Operating Agreement (OA) that went into effect on March 1, 2014, with the start of the Southwest Power Pool (SPP) Integrated Marketplace (IM).

Mr. Hakimi testified that the Company's existing OSS margin sharing credits the majority of those margin benefits (75%) to the customers, while allowing the Company to retain 25%. This long-standing treatment has successfully aligned the interests of the customers and the Company for many years. The ongoing changes in the bulk electricity markets serve to reinforce the need for such a sharing mechanism.

Mr. Hakimi testified that contrary to Ms. Fisher's assertion, elimination of the margin sharing could have a detrimental impact on both the customers and the Company if the OSS activity is no longer aggressively pursued.

According to Mr. Hakimi, Ms. Fisher's recommendations to duplicate OG&E OSS margin sharing treatment for PSO and its customers was problematic in at least two respects. Firstly, the OSS margin sharing methodology ultimately approved in OG&E's case was the result of a settlement agreement. Such outcomes are the result of give and take negotiations by all parties in reaching a 'global' result that all parties agree to. Thus, the Commission, with good reason, does not treat the resolution of any one component of the settlement agreement as precedent setting. Secondly, and perhaps just as significantly, the issues, and the existing treatment of OG&E's OSS margins, were substantially different than the set of facts regarding PSO's margin sharing at issue in this case. Furthermore, PSO has been and is currently more active in the off-system market than OG&E, and adopting a settlement decision from the OG&E rate case for PSO without consideration of the differences in the two companies is not appropriate.

Mr. Hakimi further testified that he did not agree when Mr. Garrett stated that under the newly-deployed SPP IM, "SPP will decide when PSO's generating units will supply energy to other parties in the market." And secondly, when he stated that "SPP will develop the accounting and billing records to facilitate the physical and financial accounting for such transactions [*sic*]." At the most basic level, Mr. Garrett makes no mention of one of the most fundamental features of the SPP IM construct. The multiple new markets, policies, procedures, requirements and responsibilities resulting from the deployment of the new SPP IM are designed to minimize the cost for the SPP footprint as a whole. SPP is not tasked with optimizing the off-system sales margins for any participants – whether that participant happens to be PSO, or any one of the dozens of other market participants. Instead, SPP is tasked first with maintaining reliability, then with matching generation supply with load demand based on market prices. Keeping the OSS margin sharing in place will continue to provide incentives to PSO to maintain and operate its generation fleet so as to take full advantage of the market for the benefit of its customers.

According to Mr. Hakimi, PSO has every expectation that its participation in the SPP IM can produce substantial benefits for its customers – but the realization of those benefits, including the optimization of OSS margins, will depend in large part on the continuing activities of PSO, through AEPSC's commercial operations organization, to aggressively pursue those margins, working in the new IM framework established by SPP. It was Mr. Hakimi's testimony that Mr. Garrett's cursory description of the SPP IM severely overstates the role of SPP in regards to the optimization of PSO's OSS margins, while at the same time fails to recognize the major role of AEPSC and PSO personnel in all phases of the SPP IM.

Mr. Hakimi did not agree with Mr. Garrett's testimony starting at page 45 that the OCC was not notified of the filing made at the FERC to amend the West Operating Agreement (West OA).

Mr. Hakimi testified that PSO notified the PUD of the FERC filing. EXHIBIT ANH-1R is a copy of an email that was sent to the PUD with the October 1, 2013, FERC filing attached to the email.

Mr. Hakimi further testified that the change to the West OA removing Internal Economy (IE) transactions between PSO and SWEPCO starting on March 1, 2014, did not have an impact on PSO's revenue requirement. Therefore, there was no need to address the AEP West OA amendment in PSO's current rate case.

Mr. Hakimi testified that Mr. Garrett's IE Transaction proposals were not reasonable. Starting on March 1, 2014, PSO's customers have started to realize fuel cost savings from the broader SPP IM, which for [*sic*] PSO has replaced IE transactions from its affiliated utility company SWEPCO. Furthermore, even if IE transactions were feasible, they would need to occur under a FERC-approved agreement requiring the concurrence of all the parties to the agreement and not just one of the parties. Given that reinstating IE transactions is not feasible, Mr. Hakimi recommended [*sic*] the Commission not accept Mr. Garrett's recommendation to direct PSO to perform production cost studies related to the elimination of IE transactions. Such a study would not [*sic*] be based on any meaningful operating scenario for PSO and would be an inefficient use of PSO resources.

Summary of Direct and Rebuttal Testimonies of John J. Spanos

John J. Spanos with the firm of Gannett Fleming, Inc., 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, 2012. 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, 2012.

	Current		Proposed	
Function	Rates	Proforma Expense	Rates	Expense
Steam	1.58	$18,470,035	2.40	$28,148,131
Other	2.04	3,122,830	3.33	5,082,642
Transmission	1.94	13,641,407	2.42	17,058,860
Distribution	2.40	44,449,540	3.00	55,632,192
General	3.24	4,572,928	5.01	7,075,353
Total		$84,256,740		$112,997,178

The major components that caused rates to change by function were 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.
- Distribution Plant: the more negative net salvage percents for many accounts.
- General Plant: a shorter life for Account 391.1 and a more appropriate net salvage percent for Account 390.0.

Mr. Spanos further testified that the rates currently in effect 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 2006.

In rebuttal testimony, Mr. Spanos stated he was responding to the direct testimonies filed by Public Utility Division (PUD) witness Carolyn Weber and Oklahoma Industrial Energy Consumers (OIEC), Wal-Mart Stores, LP and Sam's East, Inc. witness Jacob Pous on depreciation related issues.

Mr. Spanos addressed the recommendation of both Ms. Weber and Mr. Pous to defer the implementation of the depreciation study until a future cause. He explained in detail, the depreciation study demonstrates that depreciation rates are too low for many accounts; therefore, deferring the study will result in deferring costs to future customers. Additionally, to the extent that the Commission believes any of the adjustments proposed by Ms. Weber or Mr. Pous are necessary, this should not result in the entire study being discarded.

Mr. Spanos addressed the specific adjustments and criticisms to the depreciation study that each witness proposes. These included:

- <u>Mr. Pous' complaints regarding the level of support in the study</u>. Mr. Spanos explained 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. In contrast, Mr. Pous' recommendations are well outside the mainstream of depreciation practices and his analysis is not based on widely accepted practices.

- <u>Terminal net salvage for production plant accounts</u>. In this section, Mr. Spanos explained that net salvage estimates must be stated at a cost for the time period at which these costs 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. He addressed Mr. Pous' claims regarding the value of the sites for the Company's plants.

- <u>Interim survivor curves for production plant accounts</u>. Despite Mr. Pous' misleading statements to the contrary, the methodology for interim retirements that I have used in the depreciation study is widely accepted in the industry and is appropriate for this proceeding. It is in fact a method that is more precise than the approximation that Mr. Pous 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.

- Mass property life analysis. Mr. Pous has recommended adjustments to the service life estimates I have made for seven accounts. For most accounts, the primary difference between my estimates and those of Mr. Pous is the interpretation of the Company's historical data. As I will explain in detail, Mr. Pous' analysis is not consistent with proper judgment or authoritative depreciation texts. The results of his analyses are therefore inappropriate.

- Mass property and interim net salvage. Mr. Pous has recommended adjustments to the net salvage estimates for three transmission plant accounts and for the interim net salvage estimates for steam production and other production accounts. Mr. Spanos explained in making his estimates, Mr. Pous chose [*sic*] to ignore the Company's actual experience and proposed estimates that deviate significantly from the historical data. As a result, his analysis produces estimates that are far less negative than appropriate.

Summary of Direct and Rebuttal Testimonies of Rhoderick C. Griffin

Mr. Rhoderick C. Griffin, Manager, Regulated Accounting, of 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).

Mr. Griffin 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 (FERC) Uniform System of Accounts accounting and reporting requirements.

Mr. Griffin's testimony included an overview of the affiliate costs included in Public Service Company of Oklahoma's (PSO or Company) 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 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. Griffin testified that W/P P-7, the PSO cost of service amount presented in this filing includes $58,356,309 of affiliate costs. AEPSC accounts for $57,750,936 of these costs, which are summarized on EXHIBIT RCG-1, with a more detailed view on EXHIBIT RCG-2. PSO has included $605,373 billed from other affiliates in cost of service. These other affiliate costs are detailed on W/P P-7 and are discussed in the testimony.

According to Mr. Griffin, PSO's total company operations and maintenance (O&M)

expense as shown on Schedule H of the filing package is $258.1 million, and the $58.4 million of affiliate costs included in that number represents 23 percent of the total O&M being requested in this case. The remaining 77 percent is incurred directly by PSO and not through an affiliate.

Mr. Griffin further testified that the total costs billed from AEPSC to PSO decreased by $9,477,169, or 14.1 percent, when compared to Cause No. PUD 201000050, which was PSO's last base rate case. The decrease is primarily related to a reduction in the AEPSC headcount providing service to PSO. Mr. Griffin made adjustments to the test year billing from AEPSC. The AEPSC costs have been adjusted to develop a normal, ongoing level of costs billed to PSO.

Mr. Griffin's 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 so 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. Griffin testified he was confident that PSO receives from AEPSC effective services when they are needed at a cost that is less than PSO would pay on a stand-alone basis.

Mr. Griffin's rebuttal testimony rebuts the adjustments to AEPSC's labor and related costs presented in the Responsive Testimonies of Oklahoma Industrial Energy Consumers (OIEC) witness Mark E. Garrett and of Oklahoma Attorney General (AG) witness Edwin C. Farrar. [*sic*]

According to Mr. Griffin, OIEC witness Garrett recommends a total reduction of $3,336,718 for AEPSC's labor billed to PSO ($3,110,579) and related payroll taxes ($226,139). AG witness Farrar recommends removal of Public Service Company of Oklahoma's (PSO) proposed pro-forma adjustment for AEPSC labor billed to PSO, which totaled $798,078.

Mr. Griffin testified that Mr. Garrett failed to include the full amount of AEPSC's payroll in his recommendation, and neither Mr. Garrett nor Mr. Farrar include a payroll merit increase that has already occurred. PSO's updated pro-forma, an increase to expense of $1,568,567, is the best known and measurable adjustment for the increase in ongoing expense PSO will incur for the services provided by AEPSC. This amount is based on the actual six-month period ended January 31, 2014, as provided in the response to Data Request AG 2-13, which is included as EXHIBIT RCG-1R, and includes the full amount of AEPSC labor and related costs during that period.

According to Mr. Griffin, OIEC Witness Garrett's calculations were flawed because he failed to use the full amount of labor billed to PSO from AEPSC. Mr. Garrett only used the portion of AEPSC's labor amounts for his computation pertaining to productive labor, and did not include the payroll costs associated with non-productive time for items like employee vacations, sick time, and bereavement. AEPSC's labor billed to PSO includes both productive and non-productive time. Mr. Garrett's methodology is also flawed because he calculated his adjustment using the months of November, December and January, which are not representative of the costs AEPSC will bill to PSO during a full year due to the amount of vacation and holiday days used during these months. Lastly, neither Mr. Garrett nor Mr. Farrar included the merit increases granted to employees beginning April 2014, which are a part of the Company's ongoing costs.

Pre-filed Responsive Testimony Summary of Robert C. Thompson, CPA

EXECUTIVE SUMMARY

My testimony focuses on the following issues:

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 ($641,941).

Accumulated Deferred Income Tax: PUD proposes an adjustment to update accumulated deferred income tax to the 6-month post test year balance at January 31, 2014. PUD's adjustment will decrease accumulated deferred income tax included in rate base by ($18,215,515). Also, ADIT related to the inclusion of Automated Meter Infrastructure (AMI) in rate base also decreases ADIT by ($2,093,774).

Prepaid Pension Asset: PUD supports the inclusion of $106,502,775 in prepaid pension assets in rate base as proposed by PSO.

Factoring Expense: PUD proposes to adjust the factoring expense by ($37,079) to reflect PUD's revenue requirement.

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 $1,323,648.

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 $10,073,671.

Southwest Power Pool Transmission Tracker (SPPTC): PUD is recommending SPPTC be maintained in its current configuration. Also, recommending that any costs from OK Transco be adjusted to reflect PSO's authorized ROE to calculate costs recovered from PSO's customers.

Vegetation management: PUD is proposing to include vegetation management expenses in base rates. The vegetation management program has for the previous 10 years been recovered through a rider. PUD believes the necessity of the rider has ended and recovery through base rates is appropriate.

Pre-filed Testimony Summary of Javad S. Seyedoff, MBA

I filed pre-filed direct testimony on April 23, 2014 in Cause No. PUD 201300217 – Public Service Company of Oklahoma's ("PSO" or "Company") Rate case audit in which I presented the results from my review.

The Public Utility Division ("PUD") reviewed the following areas: Payroll Expenses, Payroll Taxes, Pensions, Incentive Compensations, Directors Fees and Executive Salaries, Insurance, Injuries and Damages, Regulatory Expenses, Current Rate Case Expenses, Utility Assessment, FERC Assessment, AEPSC Adjustments, Affiliate/Subsidiary Transactions and Corporate Allocations. For the areas listed above, PUD recommends six adjustments for a total decrease to expenses of ($4,367,175.18).

PUD recommends Adjustment No. PUD H-15 in the amount of ($728,638), which reduces [*sic*] Payroll Expenses. This adjustment recognizes six months post test year data, which captures recent information. For Payroll Taxes, PUD recommends Adjustment No. PUD H-16 in the amount of ($52,958.46), based on PSO's effective FICA rate of 7.2681 percent. PUD recommends the removal of $120,952 for Supplemental Pension expenses from Pension Expenses. Therefore, PUD recommends Adjustment No. PUD H-17 in the amount of $90,647 to reduce Pension Expenses.

PUD recommends Adjustment No. PUD H-18 in the amount of ($799,016) to address PSO's Annual Incentive Compensation Plan and Long Term Incentive Compensation Plan Expense. This adjustment includes ($296,690.60), which equals 50 percent of expenses associated with the Annual Incentive Compensation Plan. PUD's adjustment decreases PSO's adjustment level from ($3,510,612.27) to ($3,807,302.88). PUD recommends this portion to be consistent with PUD's recommendation in previous rate cases and because PSO has not shown any different support in this rate case to support increased percentage. Adjustment No. PUD H-18 also includes ($502,325.54) to decrease Long Term Incentive Compensation Plan Expense, which decreases PSO's adjustment level from ($416,828.45) to ($919,153.99). Long term incentive compensation is designed to generate profits to shareholders above expectations. This increase of profit to shareholders does not benefit ratepayers.

Likewise, for AEPSC billed adjustments, PUD recommends Adjustment No. PUD H-22 in the amount of ($2,613,978) to decrease AEPSC's Annual Incentive Compensation

Expense by ($223,299.39) and to decrease AEPSC's Long Term Incentive Compensation Expense by ($2,390,678.19).

For Current Rate Case Expenses, PSO estimated current rate case expenses in a response to data request JS-1-3 at $740,000. However, PSO's current expense level is $281,003.60. PUD recommends that PSO provide all additional rate case expenses for the remaining $458,996.40 through the issuance of the Final Order in this cause. For Prior Rate Case Expenses, PUD recommends an annualized amount of $245,817; whereas, PSO recommends an annualized amount of $327,755, which represents an 18-month amortization. PUD recommends amortization of 24 months, based on prior Commission orders that set the amortization period at 24 months. Therefore, PUD recommends Adjustment No. PUD H-19 for ($81,938). The total remaining balance of prior rate case expenses is $491,633.

Pursuant to statute, PUD reviews revenues and expenses for six months post test year. The total amounts of these adjustments represent reductions of $00.00 in PUD Schedule B and a decrease of ($4,367,175.18) in PUD Schedule H.

PUD JS H-15(Payroll Expenses)	($728,638.00)
PUD JS H-16(Payroll Taxes)	($52,958.46)
PUD JS H-17(SFAS 87, Excess Pension)	($90,647.00)
PUD JS H-18 (Annual Incentives)	($296,690.60)
PUD JS H-18 (Long term Incentives)	($502,325.54)
PUD JS H-19 (Rate Case Expenses)	($81,938)
PUD JS H-22 (AEPSC – Annual Incentives)	($223,299.39)
PUD JS H-22 (AEPSC – Long term Incentives)	($2,390,678.19)
Total Adjustments	($4,367,175.18)

Payroll Expense: PUD reviewed Company's base pay over twelve months ending six months [*sic*] post test year, compared to Company's proposed pro forma level indicated in Company's response to the Attorney General's data request AG-2-13 attachments 1 and PUD JS-2. PUD recommends PUD JS H-15 adjustment in the amount of ($728,638.00) to reduce base payroll to six month post test year level.

Payroll Taxes: Company made adjustment W/P H-2-8 in the amount of $107,547 to decrease Federal Insurance Contributions Tax (FICA) expense to reflect pro forma adjustments to payroll and incentive compensation expenses.

PUD proposed an [*sic*] adjustment to reflect the final known and measurable amount of payroll expense. PUD's adjustment to payroll changes PSO's payroll tax adjustment. PUD recommends adjustment PUD JS H-16, which is a reduction in the amount of ($52,958.46).

Pension Expenses: PUD reviewed current testimonies, prior testimonies, supporting documentation, and company responses to data requests PUD JS-13, 14, and 15, SFAS 87, 106, and 112 actuarial reports along with PSO's adjustments. PUD recommends disallowance of Supplemental Pension (known as Qualifying Pension) in SFAS 87 test year pension expense (W/P H-2-2) in the amount of $120,952. Supplemental Executive Pension benefits do not benefit the ratepayers. Removal of Qualifying Pension, as proposed in PUD JS H-17, will decrease PSO's adjustment level in the amount of ($90,647).

Incentive Compensation Expenses: PSO decreased the expense level of annual incentive compensation for the test year by ($3,510,612) and long term incentive compensation expense by ($416,828). Adjustment WP H-2-7 decreases O&M expenses in the total amount of ($3,927,441). Company applied 68.44% (expense to capital ratio) to target level of annual incentive compensation to calculate the annual incentive compensation adjustment of ($3,510,612) and used 64.20% (expense to capital ratio) to targeted level of long term incentive compensation to calculate the long term incentive compensation adjustment of ($416,828). PUD's adjustment decreases PSO's adjustment level from ($3,510,612.27) to ($3,807,302.88). PUD proposed adjustment PUD JS H-18 decreases annual incentive compensation by an additional ($296,690.60).

PUD's adjustment decreases PSO's adjustment level from ($416,828.45) to ($919,153.99). PUD proposed adjustment PUD JS H-18 decreases long term incentive compensation by an additional ($502,325.54).

Insurance Expense (Property, Liability, and Workers' Compensation): PUD reviewed PSO's responses to data request PUD JS-7 and supporting documents. PUD does not propose any adjustments to the test year end total included in cost of service for insurance expenses because PSO's test year end totals reflect a normal level.

Injuries and Damages Expense: PUD does not propose any adjustments to injuries and damages expense. PUD reviewed PSO's responses to data request PUD JS-8 and other responses including sample documents provided by PSO.

Outside Services: PUD reviewed outside service/attorney fees (legal fees) looking for those expenditures that were an unnecessary cost in providing electric service for customers. PUD asked for supporting documentation for invoices greater than $10,000 during the test year. For accounts other than Outside Services charged to Account 923 during the test year, PUD asked for supporting documentation for invoices greater than $100,000 during the test year. PUD recommends no adjustment to outside services; however, other PUD witnesses are assigned to specific areas related to outside services.

Legal Contract Settlements: According to the Company, PSO had some human resource related settlements and the Company is not seeking recovery. PUD has no adjustment.

Regulatory Expenses: PUD reviewed prior rate case expense amounts in schedule WP H-13, including those authorized by the Commission in Cause Nos. PUD 200600285, 200800144, 201000050. PUD also reviewed the removal of OCC Assessment Fees. PSO WPH-13 consists of current and previous rate case expenses (adjustment WPH-2-16 in the amount of $327,755) and related amortizations, OCC assessment, FERC assessment fees (adjustment WP H-2-17 in the amount of ($1,562,512), PUD/AG Amortization (adjustment WP H-2-19), AEPSC Billings (adjustment WP H2-26 in the amounts of ($116,009) and ($4,791,107), and a small amount of other legal expenses. These adjustments are included in current rate case regulatory expenses.

PUD agrees with PSO's adjustments to reduce regulatory expenses because this adjustment makes regulatory expenses reasonable and consistent with previous rate cases. PUD concludes that PSO's proposed adjustments should be allowed in the cost of service. PUD is not recommending an adjustment to PSO's requested amounts.

Current Rate Case Expense: PSO estimated its amount of current rate case expense in response to data request JS-1-3 at $740,000. PSO's and AEPSC's employee payroll expenses (labor) are not included in their estimate. The amount of expenses reported by PSO totaled $281,003.60.

PSO requests that the Commission provide in its final order approval for PSO to defer as a regulatory asset or liability the difference in actual expenses when compared to the amount included in base rates and allow the difference to be addressed in PSO's next base rate filing.

PSO should be required to provide all additional rate case expenses for the remaining $458,996.40 through the issuance of the Final Order in this cause.

Prior Rate Case Expense: PSO proposed an amortization over 18 months; PUD recommends amortization of 24 months. PSO recommends an annualized adjustment (WP H-13) in the amount of $327,755. The total remaining balance of prior rate case expenses is $491,633.

PUD recommends an annualized adjustment of $245,817; PUD JS H-19 proposes an annualized pro forma adjustment (Decrease) in the amount of ($81,938).

Utility Assessment Fees (OCC): PUD does not propose any adjustments to PSO's OCC assessment fees. PSO collects the OCC utility assessment fees as the OCC invoices the fees for payment. The effect of these related transactions on PSO's books should be, and is, zero. PUD accepts PSO's pro forma adjustment of ($1,342,087) to remove the utility assessment fees from rate base.

FERC Assessment Fees: PUD does not propose any adjustment to the test year end total. PSO included $11,967 for fees assessed by FERC as a regulatory expense in schedule WP H-13 in cost of service.

AEPSC Allocation of Regulatory Expenses: During the test year, AEPSC charged regulatory expenses in the amount of $84,173 to PSO. PSO adjusted this amount to $208,519, an increase of $124,346 to cost of service. PUD questioned the payroll adjustment of $130,257 in WP H-13-1. PUD recommends accepting PSO's adjustment.

Affiliate/Subsidiary Transactions and Corporate Allocations: PUD reviewed the allocation percentages used by AEPSC in allocating certain indirect costs among PSO and other subsidiaries. Corporate allocation methodology is used by the parent company in this type of allocation, where a direct charge to the business unit or a specific relationship cannot be established, is immaterial, and cannot be linked to a subsidiary company. In PSO's previous rate case, Cause No. PUD 200800144, Order No. 564437, page 27, the Commission concluded that AEPSC's allocation factors methodologies are specific, reasonable and allocate costs to PSO on an appropriate basis. Also in Order No. 564437, the Commission found that PSO provided supporting documentation for its affiliate costs. Likewise, in this case, PUD recommends the amount that AEPSC allocated to PSO be approved.

AEPSC Adjustments: PSO made an adjustment in schedule H-2 for AEPSC adjustments W/P H-2-26 to increase or decrease nine (9) test year AEPSC affiliate billing records. PSO's adjustment WPH-2-26 will decrease and normalize the AEPSC affiliate billing records by a total of $4,907,116. PUD recommends adjustments to Incentive Compensations. PUD adjustment PUD JS H-22 to Annual Incentives will change the AEPSC adjustment level by an additional ($223,299.39). The combination of PSO and PUD adjustments remove half of PSO's requested amount of AEPSC Annual Incentive Compensation. PUD adjustment PUD JS H-22 to Long Term Incentives will change AEPSC adjustment level by an additional ($2,390,678.19). The combination of PSO and PUD adjustments remove all (100%) of PSO's requested amount of AEPSC Long Term Incentive Compensation.

The total amounts of these adjustments represent a decrease of ($4,367,175.18) in PUD Schedule H.

After a thorough review and audit of each area, PUD does not propose any other additional adjustments in my assigned areas.

Summary Testimony of Michael K. Knapp

Dr. Michael K. Knapp of the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission") filed Responsive Testimony on April 23, 2014 in Cause No. PUD 201300217. The purpose of Dr. Knapp's testimony is to review four items in the January 17, 2014 application of the Public Service Company of Oklahoma ("PSO" or "The Company") in Cause No. PUD 201300217. 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")

Dr. Knapp's testimony and its accompanying analysis developed PUD's recommendation of a fair rate of return for the Company.

Throughout his testimony, Dr. Knapp has [*sic*] used a standard for a recommended return that is consistent with the concept of a "fair rate of return" for a public utility's invested capital. The Supreme Court determined the guidelines for a fair rate of return in *Bluefield Water Works and Improvement Company vs. Public Service Commission*, 262 U.S. 679 (1923) (*"Bluefield"*), as further modified in *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*"Hope"*).

First, Dr. Knapp reviewed the current economic environment with particular emphasis on growth in gross domestic product, unemployment, inflation and interest rates. He considered the impact of the Federal Reserve's expansionary monetary policy, specifically its near zero Federal Funds rate and its likely impact on the issuance of debt both private and public. Second, in deference to the standards of both *Bluefield* and *Hope*, Dr. Knapp selected a group of comparable electric companies upon which he conducted [*sic*] evaluation. In that regard, he examined relevant financial statistics as a benchmark for PSO and its parent, American Electric Power Company ("AEP"). From there, Dr. Knapp developed Discounted Cash Flow ("DCF") analyses and Capital Asset Pricing Models ("CAPM") to estimate the ROE for each of the proxy group. Finally, he compared the proposed capital structure to the comparison group of electric utilities to determine if the Company's cost of capital is reasonable.

Dr. Knapp's DCF model produced a range of ROE estimates for AEP with a low of 8.13 percent to a high of 9.05 percent. The DCF model produced a range of ROE estimates for the proxy group of 7.98 percent to 11.72 percent. The CAPM analysis ranged from 8.35 percent to 8.62 percent for AEP. Undoubtedly, the current Federal Reserve policy of maintaining low interest rates has influenced the financial analysis. While its impact on the DCF model is indirect, the influence is more substantial on the CAPM analysis. As Dr. Knapp identified in his testimony, the yields on US Treasury securities are historically low. The comparable returns on equity comparison produced a forecasted range of 9.50 percent to 10.00 percent for AEP and a range of 9.50 percent to 9.90 percent for the comparable electric utilities.

Dr. Knapp recommended the Commission approve a ROE in the range of 9.50 to 10.00 percent. He based his recommendation on the results of his DCF models and CAPM analysis as well as his evaluation of earned ROEs of the proxy group. Owing to current Federal Reserve policy of low interest rates, he considered its impact on the financial analysis results. Next, Dr. Knapp considered that as cost recovery moves from the state level to the federal level, the portion of utility investment placed at risk and subject to this

Commission's jurisdiction decreases as well as the risk associated with it. Last, he carefully considered the impact of business risks associated with the regulatory process and noted the steps that the OCC and the state of Oklahoma have taken to mitigate them. On the balance, he recommended the lower end of his range or 9.50 percent.

After analyzing the issues and examining the relevant financial analysis, Dr. Knapp testified that the Commission allow PSO:

- To use a capital structure consisting of 51.3 percent long term debt and 48.7 percent common equity
- To receive an embedded cost of long-term debt of 5.51 percent reflecting the *pro forma* cost of debt
- A return on common equity of 9.50 percent
- A rate of return of 7.46 percent

Summary Testimony of Joel Rodriguez

Mr. Joel Rodriguez is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC") and filed Responsive Testimony on April 23, 2014 in Cause No. PUD 201300217. The purpose of Mr. Rodriguez' testimony is to present PUD's recommendation for his assigned area of expert witness expense in response to the application filed by the Public Service Company of Oklahoma ("PSO").

Mr. Rodriguez recommended adjustments [*sic*] to the expert witness expense to the Operating Income portion of PSO's rate case application. Specifically, Mr. Rodriguez adjusted the total reported expert witness expense to reflect the actual expense incurred by PSO. In addition, Mr. Rodriguez also recommended that PSO amortize the expert witness expense over a 24 month amortization schedule. The recommended expert witness expense adjustment is $1,267,094 and when amortized [*sic*] over a 24 month period the resulting annual amount is $633,547 to be recovered through the rate case regulatory asset.

Summary Testimony of Brandon Jimenez

Mr. Brandon Jimenez is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC") and filed Responsive Testimony on April 23, 2014 in Cause No. PUD 201300217. The purpose of Mr. Jimenez'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. Jimenez recommended two adjustments [*sic*] to the areas of prepayment balances and customer deposits. For the remaining five areas that Mr. Jimenez reviewed, he is not recommending any adjustments. These areas include: materials, supplies, fuel inventories, refund policy for customer deposits, interest on customer deposits, customer advances for construction, and off-system trading deposits.

For the first adjustment, Mr. Jimenez recommended PUD Adjustment No. B-8 to decrease the prepayment balance by ($2,609,490). PSO used a 13-month average for prepayment amount, after reviewing data request responses and discussions with Company staff. Mr. Jimenez believes that using the 13-month post test year average balance represents an up to date account balance. For the second adjustment, Mr. Jimenez recommended PUD Adjustment No. B-9 to reduce customer deposits by ($21,747). Mr. Jimenez believes that utilizing the 13-month post test-year average in comparison to PSO's year-end balance allows for up to date account balances and of customer deposits.

Mr. Jimenez did not propose any adjustments to the remaining five areas. First, the Company made an adjustment to its coal and fuel inventory, and Mr. Jimenez determined through research from SNL Financial and discussions with Company staff that the adjustment was appropriate. Second, Mr. Jimenez did not recommend an adjustment to customer advances for construction. Mr. Jimenez determined through reviewing data request responses, previous PSO Causes and calculated 13-month post test year average balance that no adjustment was necessary. Third, Mr. Jimenez did not recommend an adjustment to off-system trading deposits. Mr. Jimenez determined that the 13-month average reported by PSO was appropriate. Fourth, Mr. Jimenez did not recommend any changes to PSO's refund policy for customer deposits. Mr. Jimenez determined that the policy outlines the criteria for handling of customer deposits is beneficial to customers as well as the Company. Finally, Mr. Jimenez did not recommend any adjustment to interest on customer deposits. Mr. Jimenez calculated the 13-month post test-year average for customer deposits and multiplied by the appropriate short term and long term interest rates which resulted in an immaterial difference.

<u>Summary Testimony of Tracy Izell</u>

Tracy Izell is employed by the Oklahoma Corporation Commission ("OCC" or "Commission"), in the Public Utility Division ("PUD") as a Public Utility Regulatory Analyst and filed Responsive Testimony on April 23, 2014. The purpose of her testimony was to present PUD's recommendation of the Ad Valorem Taxes, Taxes other than Income Tax, Analysis of Bad Debt, Tax Collections Payable, Deferred Credit and Debit Balances and Information/Misc/Sales Expenses.

PUD examined testimonies and workpapers of PSO, issued Data Requests and emailed PSO staff for information pertaining to the above accounts. After analyzing the accounts, PUD did not propose an adjustment to Taxes other than Income Tax, Analysis of Bad Debt Expenses, Tax Collections Payable and Deferred Credit Balances and Misc Deferred Debit Balances. PUD did propose an adjustment of ($114,338.94) to Information/Misc/Sales Expense for monogramming and shirts. PUD believes the ratepayers should not bear this expense. PUD also proposed an adjustment of ($3,207,893) to Ad Valorem Taxes. PUD believes this more closely represents an accurate view of Ad Valorem Taxes for PSO.

PSO previously reported adjustments of ($18,936,156) to Information/Misc/Sales Expense categories. PUD further reduced the number by ($144,338.94) for payments made for shirts and monogramming citing a code from the Federal Regulations account 907 stating that "in the general direction and supervision of customer service activities, the object is to encourage safe, efficient and economical use of the utility's service." [*sic*] Direct supervision of a specific activity within customer service and informational expense classification shall be charged to the account where in the costs of such activity are included.

PSO reported increased adjustments to Ad Valorem Taxes of $2,642,564. PUD reduced Ad Valorem Taxes by $3,207,893. PUD believes the requested amount is not fair or reasonable for Oklahoma Ratepayers to bear.

Summary of Testimony Tonya Hinex-Ford

Tonya Hinex-Ford is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation as an Energy Group Coordinator. Her testimony provided a recommendation for the application filed on January 17, 2014, by the Public Service Company of Oklahoma ("PSO") for the test-year ending July 31, 2013, for an order of the Commission authorizing a modification of its rates, charges, and tariffs for retail service in Oklahoma. Ms. Hinex-Ford's testimony covered the Large Invoices over $250,000 and PSO's gridSMART® project.

Ms. Hinex-Ford recommended no adjustment to the Large Invoices over $250,000 excluding fuel, because the responses to inquiries from PUD were answered satisfactorily.

Ms. Hinex-Ford also provided testimony regarding the gridSMART® project. PUD did not recommend approval of the gridSMART® project. PUD would like PSO to continue the analysis of its gridSMART® project and the programs and service offerings that will be both beneficial to the Company and to the ratepayers. Moreover, PUD believes that any subsequent proposal for AMI deployment should include, but should not be limited to; the guaranteed savings on O&M associated with labor, vehicles, and overheads; effective pricing/technology combination for customers; and for those customers that do not have internet access and have AMI meters, a Home Energy Report be made available free of charge to LIHEAP and Senior Citizens.

In addition, PSO should continue to analyze the results from the evaluations performed on the VVO performance and the DA studies, which will be available in mid-2014. Furthermore, when these results are available, PUD requests to receive a copy of the report and to conference with PSO concerning the results. Meanwhile, PUD encourages PSO to continue its efforts to learn from the experiences gained from the Owasso, University of Tulsa Campus, Okmulgee and Sand Springs AMI deployments.

<u>Summary Testimony of Luis F. Saenz</u>

Luis Saenz is employed by the Oklahoma Corporation Commission ("OCC" or "Commission"), in the Public Utility Division ("PUD") as the Cost of Service Coordinator and filed Responsive Testimony on May 07, 2014 and Responsive Testimony Errata on May 23, 2014. The purpose of his Responsive Testimony was to present PUD's recommendation for the distribution of revenues among customer classes and their cost of service study that reflects a total company increase in revenues of $2,913,546 at a rate of return of 7.46 percent and for a total operating revenue requirement of $599,695,686. The purpose of his Errata Responsive Testimony was to amend Exhibit LS-03 to remove the revenues of the "Special Contract Customer" from the total revenue requirement as to avoid a double recovery through the proposed rates.

In Mr. Saenz's [*sic*] Responsive Testimony filed May 04 [May 07] [*sic*], 2014, PUD disagreed with the way the Company classified their Distribution system. PSO classified FERC accounts 364 through 368 as demand only, and proposed to include 53 percent of the demand related distribution costs in the customer charge. PUD believed under this approach PSO faces the potential to adversely affect small users within the same class if their usage characteristics are not in line with others in the group. It will also weaken price signals to customers, removing the incentive to engage in energy efficiency activities. A Zero-Intercept Study was proposed by PUD to be performed by PSO in the future.

Investment in the Broken Arrow Water Plant Substation of $1,584,280 was directly assigned to FERC account 362-Station Equipment. However, these facilities should not have been directly assigned to the SL2 class but should have been included with the other investment in FERC Account 362. PUD made the correction to reassign the Broken Arrow Water Plant investment to the total FERC account 362. This reduced the allocation to the SL2 class.

PUD believed that changing the Transmission allocator from a 4CP to a 12CP for the Company's Transmission function was contrary to the design and nature of the Company's Transmission system, and failed to represent a summer peaking utility. Adopting a 12CP allocator for its Transmission function will not only send the wrong signal to its customers, but it in effect will punish the very customers who have been responding to rates and price signals and have worked to move load outside of the summer months. Therefore, PUD recommended that the Company uses a 4CP A&E allocation method which will reflect both how the Transmission system is planned to meet peak demands, and the need to maintain a reasonable excess of capacity in order to handle increased loading in the future, as mentioned above.

Based on PUD's base rate, PUD recommends an overall company revenue increase of $2,913,546 at a rate of return of 7.46 percent for a total operating revenue requirement of $599,695,686. PSO's retail customers were allocated $4,306,961, while their Federal jurisdiction received a decrease of $1,393,415, for a total PSO revenue increase of $2,913,546. Below is an excerpt from PUD's proposed COSS (Exhibit LS02) comparing the total company revenue requirement and its distribution to the retail customer classes under present rates to the equalized return at proposed ROR of 7.46 percent. This attempts to move classes closer to a parity of one.

Customer Class	Total Proposed Revenue	Revenue Distribution
Residential	281,796,050	6,470,393
Lighting	10,798,392	(269,618)
C&I SL5	177,649,953	(1,384,147)
C&I SL4	3,834,646	(120,008)
C&I SL3	37,000,000	(518,639)
C&I SL2	29,428,749	231,807
C&I SL1	6,275,000	(102,827)
Total Retail	**546,782,791**	**4,306,961**

Table 1. PUD Proposed Revenue Distribution exluding [*sic*] other operating revenues

With regard to PSO's Variable Peak Pricing Rate Schedule ("VPPRS") pilot program, PUD believed that the Company should look into modifying the VPPRS pilot program structure in order to attract more participants and yield energy savings, as opposed to discontinuing this option to customers.

On May 23, 2014, Mr. Saenz filed Errata Responsive Testimony which made changes to Rate Design Exhibit LS-03 to remove the revenues of the Special Contract Customer from the total revenue requirement to avoid double recovery through the proposed rates. Revenues for the Special Contract Customer are calculated by the same percent change assigned to the SL2 class. At the same time, all other customer classes received a credit for that special contract revenue in their proposed class revenue. The calculated revenue requirement for the Special Contract Customer is $3,754,600. Below is the credit allocation to the remaining customer classes:

Customer Group	Proposed Special Contract Class Allocation
Residential	
LURS	$17,531
RS	1,903,287
Total RS	$1,920,818
Commercial	
LUGS	$350,804
GS	$661,838
PL	$258,536
UMS	$3,304
MP	$2,146
Commercial Total	$1,276,627
Lighting	
GSL	$103
OL	$4,584
SL / NR	$60,872
M SL	$11,193
TS	$465
Total Lighting	$77,216
Industrial	
SL3 Total	$261,750
SL2 Total	$203,693
SL1 Total	$44,495
Total Retail	$3,784,600

Table 2. Special Contract Revenue Allocation to Customer Classes

PUD also recommended the Commission have the opportunity to review revenues from this Special Contract and the need for its continuation since it has been in place for more than three decades.

After identifying and removing the revenues of the Special Contract, rates were designed to meet the revenue requirement by customer class as shown below for the Residential customer class[1].

Class	Present Non-Fuel Base Revenue w/out Spec Cont.	Target Non-Fuel Proposed Revenue w/out Spec Cont. - Base Rate Design
LURS 020	$2,495,444	$2,595,345
RS 015	$270,924,630	$277,295,121
Total Residential	$273,420,074	$279,890,467
Special Contract	$1,905,584	$1,920,818
COS Revenue	$275,325,658	$281,811,285

RS 015	Proposed Non-Fuel Price
On-Peak	
Base Service Charge	$16.16
Energy Charge	
0-1350	$0.0546
over 1350	$0.0460
Off-Peak	
Base Service Charge	$16.16
Energy Charge	
0-475	$0.0306
476-1250	$0.0202
over 1250	$0.0117

LURS 020	Proposed Non-Fuel Price
On-Peak	
Base Service Charge	$9.98
Energy Charge	
0-600	$0.0255
over 600	$0.0680
Off-Peak	
Base Service Charge	$9.98
Energy Charge	
all	$0.0255

Table 3. Residential Class Rate Design

Summary Testimony of Sharon Fisher, MBA

Sharon Fisher is employed by the Public Utility Division (PUD) of the Oklahoma Corporation Commission (Commission) as a Coordinator of the Fuel Group. The purpose of Ms. Fisher's testimony in the current cause is to present PUD's review and recommendations regarding removal of energy related fuel costs from base rates, including Off Systems Sales of Electricity (OSSE), Base Load Purchased Power (BLPP), Purchase Power Capacity costs (PPC or the Exelon Rider) credited and/or recovered through the Fuel Adjustment Clause (FAC).

PUD recommends all energy-related fuel cost recovery come through its FAC. This removal of all energy related costs from base rates offers greater transparency in a separate, stand-alone FAC Rider. This will have no monetary impact on customers' bills. A customer's bill for a given amount of energy use will be exactly the same amount whether fuel is in the base rates or in the FAC. This will require an operating income adjustment to remove $4,758,795 for fuel and purchase power from base rates. PUD adjustment H-20 ($4,758,795) removes both the cost and revenue associated with fuel and purchase power that was embedded in base rates.

With regard to off system sales, Ms. Fisher testified that the OSSE is a credit whereby the Company flows back to its customers the credits it receives for the sales of power generated by the Company and sold to ancillary or off-system customers through the SPP. The cost of

[1] Refer to Exhibit PUD LS03 from Errata Testimony filed on May 27, 2014 for a complete breakdown of rates per customer class.

generating the power is included in the FAC. This should be a net benefit to the Company's ratepayers.

Ms. Fisher's recommendation was to include Base Load Purchased Power (BLPP), and Purchase Power Capacity costs (PPC or the Exelon Rider) recovery through the Fuel Adjustment Clause, for a consistent manner of oversight and review of fuel-related charges and credits through an established method of periodic true-up. This recommendation does not affect the recovery of the costs. It effects the provisions for tracking and true-up within the PUD's review process.

Summary of Testimony for Carolyn J. Weber, CPA

Carolyn J. Weber is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as an Accounting Coordinator. Ms. Weber's testimony focused on the following issues:

Plant in Service: PUD proposes adjustments to update plant in service to the 6-month post test year balance at January 31, 2014 and to add back into plant the AMI (gridSMART) tangible and intangible assets, which PSO had excluded from their pro-forma rate base in order to recover them through a rider. PUD's adjustments B-3 and B-5 increase plant in service included in rate base by $121,951,955.

Construction Work In Progress: PUD proposes an adjustment to update Construction Work in Progress ("CWIP") to the 6-month post test year balance for CWIP that has been placed in service as of January 31, 2014, which was zero. PUD's adjustment B-2 decreases CWIP included in the pro-forma rate base by $35,523,845.

Accumulated Depreciation, Accumulated Amortization, and Asset Retirement Obligation ("ARO") Liabilities: PUD proposes an adjustment to update accumulated depreciation, accumulated amortization, and asset retirement obligation liabilities to the 6-month post test year balance at January 31, 2014, including the accumulated depreciation and accumulated amortization on AMI (gridSMART) assets. PUD's adjustment B-4 increases accumulated depreciation, accumulated amortization, and ARO liabilities included in rate base, under the name of Accumulated Depreciation by $16,117,104, which is a decrease to rate base.

Asset Retirement Obligations ("ARO"): PUD reviewed the information PSO provided concerning their processes for creating, updating, and adjusting AROs and methods for including in rate base and revenue requirement. PUD recommends tentative approval of PSO's method to include the ARO assets in Plant and ARO liability in Accumulated Depreciation for rate base purposes and to include depreciation expense on ARO assets and accretion expense on ARO liabilities in the revenue requirement. PSO provided information on AROs in the response to CJW DR #3-3, #3-5, and #3-6. PSO's response to CJW DR #3-6 confirmed that PSO created an ARO for asbestos removal on the Tulsa General Office (Headquarters Building) in December 2012, which was a year before the building was purchased. PUD has not determined the effect that creating the ARO in December 2012 instead of December 2013 would have on ratepayers.

<u>Gain and Loss on Settlement of Antlers Service Center AROs:</u> PUD reviewed PSO's response to CJW DR #2-6 regarding the PSO pro-forma adjustment supported on PSO's W/P H-2-41 to remove the net gain on the Antlers Service Center ARO of $17,161 from Operating income. PUD recommends adjustment H-14 to reverse the PSO pro-forma adjustment as the ratepayers provided the funding for the ARO through base rates and should receive the benefit of any net gains on the settlement or retirement of the ARO. This is an increase to the pro-forma operating income of $17,161.

<u>2012 Depreciation Study and 2013 Demolition Study</u>: PUD recommends remaining with the depreciation schedules that conform to Order No. 564437 in PUD Cause No. 200800144, and which were affirmed in the Joint Stipulation contained in PUD Cause No. 201000050 [*sic*] in Order No. 581748. PUD found issues with the 2012 Depreciation Study which are discussed more fully in the body of my testimony. Also, according to PSO, they will file another rate case in 2015 and will address the issues of the environmental settlement agreement with the EPA and its impact on Production Plant in that case. PUD anticipates that another depreciation study will be required for the next rate case in order to address the improvements and the plant closures required in PSO's settlement with the EPA. The 2015 rate case is the appropriate time to adopt new studies, which will more adequately address some of the issues discovered during the review of the 2012 Depreciation Study. PUD recommends adjustment H-6, which is a combination of an entry to reverse the PSO pro-forma adjustment to record depreciation using the rates proposed in the 2012 Depreciation Study, and to base the depreciation expense on Electric Plant in Service as of January 31, 2014, using the approved existing depreciation rates. Adjustment H-6 reduces the pro-forma depreciation expense by $27,619,207.

<u>Depreciation Expense</u>: In addition to the changes in depreciation expense related to using the approved existing depreciation rates and the Plant in Service as of January 31, 2014, PUD recommends three additional adjustments to depreciation expense.

1) The depreciation expense needs to be adjusted to be consistent with PUD's position to include AMI program recovery through base rates instead of a rider. PSO had not included any depreciation on the AMI Meters (FERC 370.16) in the pro-forma depreciation expense. PUD adjustment H-7 for $547,032 is the amount of depreciation on the AMI meters in service as of January 31, 2014, based on the approved existing depreciation rate, which increases the pro-forma depreciation expense.

2) PUD reviewed the plant additions and retirements in test year ending July 31, 2013 and the 6-months post test year. PSO's responses to CJW DR #1 questions 11 and 12 concerning retirements related to July and December 2013 storm damage stated that the information would not be available until the end of April. CJW DR #4 requested the amount of physical retirements that were not recorded on the books or in the updated Schedules C, D, and I. In the response to that data request, PSO [*sic*] states that retirements are taken out of service when the replacement assets are placed in service and

that all retirements should be reflected in the January 31, 2014 updated schedules C, D, and I. However, those schedules include "Construction not Classified" of $152,650,631 which are included in Plant in Service and annual depreciation as of January 31, 2014. There was no corresponding entry to remove retirements associated with these new assets. Due to lack of specific information regarding the amount of retirements that were potentially not reflected in the updated Schedules C, D, and I, PUD estimated the unrecorded retirements for production, transmission, and distribution. Based on the PUD estimate of expected retirements and the composite approved existing depreciation rates for production, transmission, and distribution, PUD recommends adjustment H-8, a reduction of depreciation expense of $374,000. PUD thinks this is a conservative estimate.

3) During PUD's review of PSO's pro-forma depreciation expense adjustment as of July 31, 2013, PUD noticed that the ARO depreciation expense was inadvertently omitted from the pro-forma depreciation expense as it was not included in Line 179 Column (7) of W/P H-2-24.1, but was included in Line 183 Column (7) which was the basis of the $30,505,024 pro-forma adjustment to depreciation expense. Therefore, the pro-forma adjustment was understated by the amount of ARO depreciation as of July 31, 2013. To be consistent with adjusting Plant in Service and Accumulated Depreciation to January 31, 2014 balances, the amount of ARO depreciation that should be included as of January 31, 2014 is the amount included on the PSO trial balances for the twelve months ended January 31, 2014 of $609,422. Since effectively PSO did not have any ARO depreciation in the July 31, 2013 pro-forma depreciation expense, the PUD adjustment H-9 increases depreciation expense included in the revenue requirement by $609,422 to include ARO depreciation as of January 31, 2014.

Amortization Expense: PUD proposes to adjust the amortization expense to be based on intangibles not fully amortized as of January 31, 2014, including the AMI (gridSMART) intangibles so recovery is through base rates instead of the PSO proposed AMI rider. PUD adjustment H-10 reduces the pro-forma amortization expense by $1,457,493 to correct for amortization included in the pro-forma for other intangibles (FERC 303) that were fully amortized as of July 31, 2013, or became fully amortized prior to twelve months after January 31, 2014. PUD adjustment H-13 increases the pro-forma amortization expense to include amortization on AMI intangibles as of January 31, 2014 of $1,033,291 to be consistent with requiring recovery of the AMI program through base rates. The net decrease to the pro-forma amortization expense included in the July 31, 2013 pro-forma revenue requirement is $424,202.

Accretion Expense: To be consistent with updating the ARO plant and obligation accounts to their January 31, 2014 balances, PUD recommends adjustment H-11 to increase the accretion expense by $62,625 to the actual twelve month accretion expense as of January 31, 2014. This does not constitute approval of the AROs, merely an adjustment to be in conformity with using the 6-months post test year balances.

Headquarters Building Purchase: In adjustment H-2, PUD recommends, and PSO agreed, to decrease rent expense by $453,050 for the annual lease expense on the headquarters building (Tulsa General Office) which was included in the revenue requirement, but is no longer necessary because PSO purchased the headquarters building on December 2, 2013.

O&M Expenses related to the AMI program: To be consistent with the PUD recommendation to recover the AMI program costs through base rates, PUD is reversing the PSO pro-forma adjustment from W/P H-2-40 to remove O&M expenses related to the AMI program from the pro-forma revenue requirement. PUD adjustment H-12 reinstates these expenses in the amount of $1,178,019.

Creation of a Regulatory Asset for "Stranded" Standard Meters: PUD does not support the PSO request to create a regulatory asset for standard meters at this time. Based on PUD's analysis, PUD recommends the following adjustments to reflect fair, just, and reasonable amounts as of 6-months post test year:

PUD Adjustment		**Rate Base Increase / (Decrease)**
B-5	Update Plant to 1/31/14 for Sch C-01	$ 105,931,692
B-3	Add Back AMI Tangibles & Intangibles in Service as of 1/31/14	$ 16,020,263
B-2	Remove Construction Work in Progress as of 7/31/13	$ (35,523,845)
B-4	Update Accumulated Depreciation to 1/31/14	$ (16,117,104)
	Net PUD Additional Adjustments	$ 70,311,006

PUD Adjustment		**Operating Income Increase / (Decrease)**
H-6	Adjust to Updated 1/31/14 Depreciation Expense per WP H-2.24.1 at existing rates	$ 27,619,207
H-7	Include depreciation expense on AMI Meters as of 1/31/14 (FERC 370.16)	$ (547,032)
H-8	Adjust depreciation for unrecorded expected retirements	$ 374,000
H-9	Include ARO Depreciation as of 1/31/14 and effectively omitted from Pro-forma at 7/31/13	$ (609,422)
H-11	Adjust Accretion Expense to total of 12-months ended 1/31/14	$ (62,625)
H-10	Adjust Amortization Expense to be based on 1/31/14 for other Intangibles (FERC 303)	$ 1,457,493
H-13	Adjust to increase Amortization Expense to include 1/31/14 AMI Program Intangibles (FERC 303.16)	$ (1,033,291)
H-2	Remove Annual Rent Expense for Headquarters Bldg	$ 453,050
H-12	Reverse PSO pro-forma adjustment on W/P H-2-40 to add back AMI program O&M expense	$ (1,178,019)
H-14	Reverse PSO pro-forma adjustment on W/P H-2-41 to add back net gain on ARO settlement	$ 17,161
	Net PUD Additional Adjustments	$ 26,490,522

PUD recommends that the Commission accept PUD's adjustments B-2, B-3, B-4, and B-5 to PSO's pro-forma rate base with a total increase to rate base of $70,311,006. PUD recommends that the Commission accept PUD's adjustments H-2, H-6, H-7, H-8, H-9, H-10, H-11, H-12, H-13, and H-14 to PSO's pro-form [*sic*] operating income with a total decrease to operating income of $26,490,522 as summarized above.

Summary of the Responsive Testimony of Steve W. Chriss on Behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

Steve W. Chriss filed responsive testimony on behalf of Wal-Mart Stores East, LP, and

Sam's East, Inc., (collectively "Wal-Mart") to address issues related to the cost of service, revenue allocation, rate design, Southwest Power Pool ("SPP") tariff, and standby service tariff proposals of Public Service Company of Oklahoma ("PSO").

Wal-Mart operates 116 retail units and employs 31,692 associates in Oklahoma. In fiscal year ending 2013, Wal-Mart purchased $773.5 million worth of goods and services from Oklahoma-based suppliers, supporting 20,493 supplier jobs. Wal-Mart has approximately 52 sites serviced by PSO, primarily on the Large Power and Light Service Level 3 ("LPL SL3") and Power and Light ("PL") service schedules.

Mr. Chriss' recommendations are as follows:

1) At PSO's proposed revenue requirement, the Commission should allocate revenue so that the final approved rates in this docket produce a relative rate of return ("RROR") for all classes, with the exception of LUGS and Municipal Street Lighting, in the range of 0.9 to 1.1, and so that LUGS and Municipal Street Lighting make some movement towards the respective costs of service for those two classes.

2) If the Commission determines that the appropriate level of revenue requirement is lower than the level proposed by the Company, however, the approved revenue allocation should move further towards the respective costs of service for each class within the 0.9 to 1.1 RROR framework proposed above. If the Commission approves an overall revenue requirement decrease for PSO, the Commission should move rates as close as possible to cost of service for all classes, while also ensuring that no class receives a rate increase.

3) Wal-Mart does not oppose the Company's proposed LPL SL3 rate design at the proposed revenue requirement.

4) In PSO's next base rate filing, the Commission should require that PSO break out the base tariff rates for PL and LPL by the generation, distribution, and transmission functions.

5) The SPP Transmission Cost Tariff ("SPPTC") calculation methodology should be modified so that the SPPTC factor for demand-metered customer classes is calculated and charged on a $/kW or demand basis.

6) In regards to the interim Standby and Supplemental Service tariff ("interim SSS" or "SSS"), the Commission should clarify that the interim SSS applies only to former Real-Time Pricing customers who were moved to interim SSS in order for the Company to have a tariff to bill those customers.

7) If the Commission determines that interim SSS or a similar successor tariff are [*sic*] more broadly applicable, the provisions of the tariff should be clarified so that the standby kilowatt is set as the simultaneous thirty-minute integrated kilowatt demand recorded on

customer's generator meter at the time the customer's load meter registers the highest thirty-minute integrated kW demand during the billing period. Under this method, the billed demand will reflect the customer's actual demand, with part of the cost of the facilities covered through the base tariff charges and the rest covered by an approved standby charge. This approach preserves cost causation principles and ensures that customers do not overpay for the facility costs incurred for service.

Supplemental Rebuttal Testimony Summary of David P. Sartin

David P. Sartin, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO), filed supplemental rebuttal testimony on July 15, 2014. His testimony, coupled with PSO witness Lewellen's testimony, addressed each of Ms. Alexander's supplemental responsive testimony issues in opposition to PSO's AMI and explained that Ms. Alexander's opposition to AMI is commonplace as she has opposed AMI in every case she has filed testimony on the subject. He testified that although PSO provides a detailed rebuttal of Ms. Alexander's testimony, it is important to not get lost in the details of that discussion and lose sight of PSO's overall objective associated with the full-scale implementation of AMI, which is to improve PSO's customer service. In summary, AMI:

1. has been fully tested by PSO with pilot programs;

2. allows PSO to provide the benefits of a modernized grid to all customers;

3. is a proven technology employed by other Oklahoma utilities and used by about one-half of U.S. electric utility customers;

4. permits customers to know more about their energy usage and reduce their electric bills;

5. generates operational cost savings to the benefit of all customers;

6. enhances outage restoration capability;

7. allows electronic meter reading that improves bill accuracy;

8. virtually eliminates the time required to connect and disconnect customers;

9. improves meter reading quality by nearly eliminating estimated readings;

10. reduces customer complaints;

11. improves communications with customers;

12. enhances the safety of PSO employees; and

13. is cost effective for customers as supported by a net present value analysis, even without quantifying the unquestionable customer service benefits.

Mr. Sartin testified that PSO's AMI deployment is clearly beneficial to customers, and should be approved as recommended by the Joint Stipulation and Settlement Agreement executed by all the parties filing testimony and statements of position in this Cause, except AARP. Parties who represent all customer classes, including the residential class, support approval of AMI as a part of the Joint Stipulation. Because of the substantial benefits to customers made possible with AMI, PSO requests OCC approval in this Cause for an AMI Tariff to match cost recovery with customer benefits. The actual total AMI costs and their reasonableness remain subject to future OCC review in subsequent regulatory proceedings. Approval of the AMI Tariff will verify the OCC's support of this technology at the time PSO decided to implement it fully, subject to PSO's execution of the AMI plan set forth in Mr. Lewellen's testimony.

Mr. Sartin testified that Ms. Alexander appears to be taking exception to PSO's AMI regulatory approval plan when she explains that PSO should deploy AMI at the risk of recovery of costs in a future rate case. She is partially correct because PSO's AMI costs will be subject to final approval and risk of recovery in a future regulatory proceeding when all of the costs are known after AMI has been fully deployed. Where PSO does have a different view is the timing of the cost recovery. PSO's request is to begin cost recovery of AMI at the same time the AMI technology is placed into service and providing benefits to customers. PSO will provide the $130 million of investment necessary for customers to benefit from AMI; customers provide none of the funds necessary for PSO to deploy AMI. Until found reasonable by the OCC in future proceedings, PSO's shareholders bear the risk of the AMI investment. If the OCC determines that some portion of the AMI costs is not reasonable, the AMI Tariff and a base rate case provide the mechanisms to adjust customer billings to reflect such a determination.

Mr. Sartin also testified that PSO has not asked the OCC to approve the dollar value of its AMI investment because it has not incurred the costs to fully implement AMI. The investment remains subject to the OCC's review and approval in a future regulatory proceeding. PSO has provided conclusive and reasonable analysis that its AMI program benefits customers, and PSO has the obligation to provide relevant information to the Commission to prove its investments are used and useful, including whatever information it deems appropriate to meet its burden of proof. Further, PSO is planning to track all relevant costs and benefits for future submission to the Commission, and the Second Joint Stipulation and Settlement Agreement provides a detailed listing of information PSO will provide annually. PSO has communicated that not all of the future cost savings will be able to be quantified without some estimation because there is no accounting system that tracks costs that do not occur. Rather, accounting systems are designed to track and accumulate actual costs, which is why tracking actual AMI costs will be readily achieved and reported to the OCC. The benefits will also be reported, but will require some estimation.

To Ms. Alexander's issue of a cost cap, Mr. Sartin testified that PSO's cost recovery mechanism tracks actual AMI costs compared to billings to customers under the AMI Tariff and ensures that only the actual costs are recovered. Customers are protected because PSO will true-up annually the actual costs to the amounts recovered from customers to make sure only the actual AMI costs are recovered; no more, no less. The actual costs are subject to review by the OCC in future regulatory proceedings to make certain they are reasonable, capping PSO's cost recovery at the level determined by the OCC to be used and useful.

Regarding a cost/benefit analysis, Mr. Sartin testified that the purpose is to determine on a present value basis, over the life of the asset, if the benefits are equal to or exceed the costs. PSO's AMI project shows that the benefits exceed the costs by $7.4 million. If an adjustment is made for the bill credit issue described in Mr. Lewellen's testimony, the net benefits are reduced to $3.5 million, but remain positive. This shows that AMI is beneficial for customers because the benefits (cost savings) exceed the costs (investments and expenses) even though the analysis does not capture the benefits customers will enjoy from having their power restored more quickly after an outage, and the qualitative customer service benefits from AMI. While a larger margin is generally considered better, a lack of a large margin is no reason for concern; in particular, since AMI provides many non-quantified benefits (e.g. service quality improvements). PSO has fairly determined each of the underlying assumptions for each cost and benefit item with no significant high or low bias, and erred on the cautious side of the assumptions so as to be conservative with the results.

In response to Ms. Alexander's criticism that PSO has not guaranteed savings, Mr. Sartin testified that PSO has guaranteed a portion of the savings, consistent with the savings guaranteed by Oklahoma Gas and Electric Company in Cause No. 201000029, Order No. 576595. Beyond that, PSO will reflect the actual costs and benefits in its future rates.

Responding to Ms. Alexander's criticism that the bill impacts and net present value analysis PSO used do not include the costs of PSO existing meters, Mr. Sartin testified that the only incremental bill impact related to the cost of the AMI technology is the $3.11 per month. This is the only impact on customer's bills resulting from the Joint Stipulation. No other customer impact will result as PSO will continue to recover the costs of existing meters through base rates. These costs are not properly included in net present value calculations, because only the incremental costs and benefits are included in such calculations, and sunk costs, like existing meters, are specifically and appropriately excluded. Recovery of existing meters was also permitted in the OG&E case. Without such recovery, utilities would be inappropriately penalized for providing new technologies and benefits to their customers.

Mr. Sartin testified that the point of an avoided cost calculation is to estimate a reasonable level of costs that will not occur as a result of reduced capacity and energy, not to promise that a specified generation technology will be avoided. PSO selected a gas-fired peaking plant as a reasonable proxy for the costs to be avoided and that the method used by PSO to calculate the avoided costs is consistent with two well established and accepted methods, the Proxy Unit method and the Peaker method. The estimate is reasonable as the revenue requirement calculation is based on the recent estimated cost to construct a new simple-cycle combustion turbine, and estimated Southwest Power Pool (SPP) market around-the-clock energy costs. The combustion turbine generator is the least expensive type of generation to add to satisfy peak demand, with a lower initial installation cost than alternative generation options such as a combustion turbine combined-cycle unit. Given that most of the cost savings is from avoided capacity costs, by assuming a peaking generating unit, this estimate is conservative.

Mr. Sartin also testified that Ms. Alexander appears to have misinterpreted the Capability, Demand, and Reserves (CDR) forecast in the IRP. The CDR shows PSO anticipates needing capacity before 2025, and because of continuing load growth from oil and gas customers and an aging generation fleet, PSO may need additional capacity by 2016. All reductions in capacity and energy costs will be reflected in reduced customer electric bills through reductions in PSO's fuel adjustment clause tariff and base rates.

The latest IRP does not include assumptions for AMI-enabled demand response programs because, as noted on the first page of the IRP, it is based upon the best available information at the time of preparation, and the plans for AMI had not been finalized to the point they could be reasonably represented in the November 2013 plan. Regardless, based on PSO's capacity needs in the most recent IRP, capacity and energy will be avoided by the deployment of AMI, and PSO will reduce its need for additional generation capacity and energy. The fact that PSO does not forecast 15 years of generation investment does not mean that over that time period PSO will not invest in new generation; it had to make a reasonable assumption as to the cost of avoided capacity and energy. That is why it selected a simple cycle combustion turbine as a reasonable proxy for the avoided cost. Rather than developing avoided costs based on her assumptions as to avoided generation and associated costs, Ms. Alexander proposes to ignore avoided capacity and energy costs in the cost/benefit analysis despite the fact that utilities typically use these cost savings in their AMI analysis.

Regarding sensitivity analyses, Mr. Sartin testified that PSO does not expect the key variables used in the analysis to be substantially different than its base assumptions. Ms. Alexander provides only a single example of a utility that used sensitivity analysis, and even with the additional analysis, she did not support AMI. Since PSO fairly, albeit somewhat conservatively, determined each of the assumptions contained in the cost/benefit analysis there was little reason to conduct a variety of sensitivity analyses because of the high probability that the most likely outcome will be close to the base case. The potential costs and savings are but one part of the decision-making process with the AMI technology. The customer service benefits of AMI are not disputable. Even if the cost/benefit analysis were [*sic*] not positive by some reasonable margin, it would still be appropriate for AMI to be deployed. Prudent utility decision-making extends beyond just dollars and cents, and includes customer service benefits as well.

Summary of the Supplemental Rebuttal Testimony of Derek S. Lewellen

Derek S. Lewellen, Manager of gridSMART® and Meter Revenue Operations for Public Service Company of Oklahoma (PSO or Company), filed Supplemental Rebuttal testimony responding to the Supplemental Responsive Testimony filed by Barbara Alexander for AARP.

According to Mr. Lewellen, PSO's costs, benefits, and participation rates are based on reasonable assumptions stemming from PSO's pilot experience, the experience of PSO's sister companies, and industry experience and benchmarking. These assumptions are based upon the most probable outcomes, and the program is cost-effective in terms of the quantifiable benefits alone, as it yields a positive net present value over a 15-year period, including $11 million in guaranteed savings over the first four years.

According to Mr. Lewellen, the estimates for PSO's proposed AMI deployment are based on the costs identified from PSO's earlier AMI deployments and initial vendor pricing information, based upon leveraging the buying power of AEP, i.e. actual historical cost data. PSO also used the experience of its sister companies, AEP Texas and AEP Ohio, in validating its cost estimates.

Regarding the Pre-Pay Program, PSO did not consider the Pre-Pay Program as a consumer program, but rather another billing and payment channel for customers, such as PSO's current automatic bill-payment option and average monthly payment plan. PSO has identified all costs related to its Pre-Pay Program ($2.1 million in capital) which will be used to develop the necessary IT infrastructure that will allow the Company to implement its Pre-Pay Program. To Ms. Alexander's criticism that no O&M costs were estimated as part of this program, the Company does not foresee any O&M expenses associated with the development of this program; therefore, they were not included. Mr. Lewellen further testified that the customer education costs for PSO's Pre-Pay Program are included in the gridMGMT component in Figure 8 of his direct testimony. These customer education costs are associated with PSO's overall AMI customer education efforts (e.g. letters, newspaper ads, door hangers) that the Company has included as part of its proposed AMI deployment and are separate from customer education costs related to the tariffs (consumer programs) that are also part of PSO's proposed AMI deployment.

The costs of the rebate program were included beyond 2016. The workpaper that was part of his rebuttal testimony ("AMI Benefits Workpaper_Lewellen") included 15 years of forecasted consumer program costs, which include the rebate costs.

Mr. Lewellen testified that Ms. Alexander was correct that PSO did not include the costs of the event credits in its NPV analysis. This exclusion is arguably appropriate since cost recovery of the credits is not sought in this case and the bill credits are a direct benefit that customers receive. However, to remove any potential controversy about this issue the Company has revised the calculation. Over a 15-year period, the cost of the event credits would be approximately $3.9 million. The impact of this adjustment would reduce the net benefits to $3.5 million.

Mr. Lewellen further testified it is important to note that the only consumer program where customers may potentially incur costs is the DLC program. Although an in-home device will be necessary for the DLC program, no device is necessary for the Time of Day (TOD) and Variable Peak Pricing Residential Service (VPPRS) programs. Moreover, PSO has repeatedly stated that it anticipates that its rebate will cover the cost of the in-home device, which will be readily available through retail stores, such as home improvement stores. As far as installation costs are concerned, these off-the-shelf in-home devices are relatively simple to install using nothing more than a screwdriver. Most retail in-home device companies provide simple and easy-to-understand instructions, videos, and customer support to help with installation.

In regards to the Pre-Pay Program, there were no incremental customer costs associated with its Pre-Pay Program.

Mr. Lewellen further testified that PSO was guaranteeing $11 million over four years, not $11 million in the fourth year. The $11 million includes the $5.0 million in O&M savings that will occur during the deployment period and $6.0 million in the fourth year.

Mr. Lewellen further testified that the data PSO relied upon for the benefits related to bad debt, theft, consumption on inactive meters, and obsolete meter avoidance was provided as part of the Company's response to AG 5-7. This data formed the foundation for Company witness Lewellen's rebuttal workpaper, "AMI Benefits Workpaper_Lewellen."

Mr. Lewellen further testified that due to the difficulties of tracking funds repaid by customers due to theft, it is for this reason that PSO has used benchmarking data in determining a reasonable approximation of the extent of energy theft that is occurring on the Company's system. [sic] This is yet another benefit that AMI has over PSO's current meters, i.e. the ability to detect theft when it occurs, and investigate immediately to mitigate the issue.

Mr. Lewellen further testified that the present value benefits stemming from the reduction in bad debt, approximately $0.5 million, or less than 4% of the total benefit for this category, is attributable to PSO's Pre-Pay Program. The other 96% of this benefit is attributable to AMI's remote disconnect functionality. This information was provided in the tab "NPV Benefits" of my rebuttal workpaper, "AMI Benefits Workpaper_Lewellen."

Mr. Lewellen further testified that PSO does not anticipate any change in the participation rate for the DLC program due to a change in the ownership of the in-home device. Furthermore, as discussed in my rebuttal testimony, PSO's approach is the predominate approach used by utilities across the country. Also, once the pilot phase of the rebate program is complete, "PSO will continue the rebate program in some form." (at 9) In the workpaper that was part of his rebuttal testimony ("AMI Benefits Workpaper_Lewellen"), Mr. Lewellen included 15 years of consumer program costs, which include the rebate costs, on the tab labeled "NPV Consumer Prog."

Mr. Lewellen further testified that PSO filed a Joint Stipulation and Settlement Agreement on June 17, 2014, which was subsequently supplemented on July 9, 2014, by a Second Joint Stipulation and Settlement Agreement that if approved will require PSO to submit the following AMI-related information on an annual basis:

- The number of meters installed;
- A summary of communication plans executed;
- Participation rates of new tariffs;
- The number of automated connects and disconnects;
- Cost information (investment, O&M, guaranteed savings, etc.);
- AMI-related customer complaints;
- Percentage of AMI meters read; and
- Demand reduction and energy savings by program.

Mr. Lewellen also testified that customer service benefits are real benefits to customers and must be taken into consideration when making the decision to deploy AMI. These benefits include: increased customer education and satisfaction due to customer web portal and related tools; power outage detection through real-time access; additional and improved metering activities; quality of service improvements as a result of AMI's functionality; environmental impact mitigation; and future functionality for developing technologies.

<u>Summary of the Supplemental Testimony in Support of the Second Joint Stipulation and Settlement Agreement of Edwin C. Farrar</u>

Mr. Edwin C. Farrar pre-filed supplemental testimony in [*sic*] support of the Second Joint Stipulation and Settlement Agreement on behalf of the Attorney General of the State of Oklahoma.

Mr. Farrar testified that the Second Joint Stipulation and Settlement Agreement was supplemental to the initial Joint Stipulation and Settlement Agreement. The Second Joint Stipulation and Settlement Agreement adds a requirement for Public Service Company of Oklahoma ("PSO") to comply with the Electric Usage Data Protections Act ("Act") and provides specific reporting requirement for the Advanced Metering Infrastructure ("AMI") program. Mr. Farrar explained that the Act establishes standards to govern the access and use of customer usage data. Mr. Farrar further testified that PSO has agreed under the Second Joint Stipulation and Settlement Agreement to provide information related to the number of meters installed, customer communication and information programs, customer participation rates, automated connects and disconnects, program cost information, customer complaints, the percent of AMI meters read, and demand and energy savings by program. Mr. Farrar also suggested that the Oklahoma Corporation Commission ("OCC") initiate a rulemaking to fully comply with the Act and also suggested that the OCC conduct an investigation to determine if some provision should be made for customers to elect out of the AMI program and if so should a reasonable fee be charged for the manual reading of their meter.

AARP Testimony Summary of the Supplemental Responsive Testimony of Barbara R. Alexander filed on July 3, 2014

SUMMARY OF SUPPLEMENTAL RESPONSIVE TESTIMONY OF BARBARA R. ALEXANDER FILED ON BEHALF OF AARP ON JULY 3, 2014

Ms. Alexander provided supplementary responsive testimony to the Rebuttal Testimony filed by Mr. Derek Lewellen with respect to PSO's proposal to deploy advanced metering infrastructure (AMI) throughout its service territory and obtain cost recovery with a Rider for at least three years prior to filing a rate case.

Ms. Alexander testified that she recommends that the Commission reject PSO's proposal for a surcharge to recover the costs of the AMI investment on the grounds that customers will pay these significant costs and are unlikely to see the promised or estimated benefits in their bills and rates. She testified that if PSO is determined to deploy AMI, it should do so at the risk of recovery of the costs in a future rate case when the Commission can examine the prudence of the costs and the actual benefits prior to authorizing any cost recovery. She testified that her proposal in essence is that shareholders bear the risk that the benefits will actually be capable of being delivered in the manner and amount described by Mr. Lewellen and that the costs were prudently incurred.

Ms. Alexander further testified that her recommendation is based on the lack of factual support for this proposed investment in light of the fact that the costs will significantly exceed any reasonable level of benefits that customers will actually see in their rates and prices for electric service. She further testified that her Supplemental Responsive Testimony documents how Mr. Lewellen's projected costs and benefits are questionable and not appropriate for this Commission to rely upon to impose these costs on consumers.

I. PSO'S ESTIMATE OF THE COSTS TO DEPLOY AMI AND ITS PROPOSED CONSUMER PROGRAMS ARE NOT BASED ON SUFFICIENT EVIDENCE AND THE COMPANY'S COST RECOVERY MECHANISM SHIFTS THE RISK THAT ITS ESTIMATES ARE INCORRECT TO RATEPAYERS.

Ms. Alexander testified that the company has not updated its costs and the Company does not have a bid or a response to a Request for Proposal or any vendor quotes or documents to support the basis for estimating the costs of the new metering system. As a result, Ms. Alexander testified there is little evidence to support the Company's estimated costs and if the Company's estimates are incorrect, there is no proposal to limit cost recovery or prevent higher costs from being passed through on the AMI Rider.

PSO has estimated that its proposed Consumer Programs will cost $5.95 million in O&M costs. These programs include the Time of Use rate option, the Direct Load Control Program with accompanying thermostat rebates, and the as-yet undefined Pre Pay program that the Company states it will submit for approval later in 2014. She testified that the Company has not estimated any O&M costs to implement the undefined pre pay program during the next three years. Furthermore, the identified $2.1 million in capital costs are not described or documented in any manner by Mr. Williamson or Mr. Lewellen.

Ms. Alexander testified regarding other cost estimates that are not properly documented or included in the Company's NPV analysis. She testified that the use of a rebate for customers that purchase and install a smart thermostat [*sic*] is directly opposite to the implementation of its pilot program where customers who enrolled were provided with a similar thermostat at no cost to the customer. She testified the Company has failed to include the ongoing costs to implement this program and maintain enrollment and peak load reductions as estimated are significantly understated since it is highly unlikely that this program can sustain its projected enrollment level without a rebate comparable to the cost of the thermostat. Also, Ms. Alexander testified the Company has not included the cost of the bill credits provided to customers who agree to have their thermostat changed on high summer peak hours in its NPV analysis.

In addition, Ms. Alexander testified that the Company has not included other costs that, as a result, the customer participation costs for these programs and this investment have not been properly included in the Company's cost benefit analysis.

II. PSO'S ESTIMATES OF BENEFITS ASSOCIATED WITH CERTAIN OPERATIONAL COST SAVINGS ARE HIGHLY QUESTIONABLE AND SHOULD NOT BE RELIED UPON TO JUSTIFY THIS INVESTMENT

Ms. Alexander testified that PSO provided new estimated benefits totaling $35.3 million (NPV) for Bad Debt, Theft, Consumption on Inactive Meters, and Obsolete Meter Avoidance Benefits that were not specifically identified or discussed in Mr. Lewellen's original testimony, but are now identified with a specific estimated cost savings in his Rebuttal Testimony for the first time. Ms. Alexander further testified that the basis for predicting or estimating the avoided costs in each of these categories is questionable and not based on any Company specific analysis or any results from the pilot program. Instead, the Company has relied on "industry benchmarking" to predict these cost reductions associated with using the AMI system and this raises many concerns.

Theft of Service: Ms. Alexander testified that PSO's basis for concluding that this feature will result in theft losses equal to 0.50% of its gross revenues or $19.8 million is without any support nor has PSO documented why the Company's earlier cost benefit analysis used a benefit level for this activity of 0.25% of revenues. Ms. Alexander further testified that: (i) PSO does not base this estimated impact on its own experience with theft cases; (ii) the Company has not calculated its actual losses from its theft of service investigations because it does not track the funds repaid by the customers who were accused of this action; and (iii) PSO did not capture this information from its pilot program. Therefore, Ms. Alexander testified that PSO cannot even identify the net costs of current theft incidents, let alone predict the impact of a new AMI system on this cost category and as a result, PSO does not have a reasonable basis for predicting the actual impact of what is likely to occur with the AMI system.

Reduce Bad Debt: Ms. Alexander testified that PSO estimates that it will reduce bad debt by 50% of existing levels, amounting to $13.8 million in savings or benefits. She stated that this appears to be based primarily on its as yet undefined and not yet approved Pre Pay program and PSO claims this level of bad debt reduction is "based on experiences at other electric utilities," without any citation to any published reports from the unidentified utilities. Again, Ms. Alexander testified that this estimate is without any support based on the record of PSO's experience with its AMI pilot program in reducing bad debt.

Reduced Consumption from Inactive Meters: Ms. Alexander testified that she did not object to this benefit category and its estimated cost savings is minimal at $0.4 million.

Obsolete Meter Avoidance: I do not object to this benefit category and its estimated cost savings at $1.2 million.

Savings of the billing and call center and the "other" categories: Ms. Alexander testified that Mr. Lewellen's estimated cost savings of $0.7 million (NPV) by using the AMI interval usage data to more expeditiously address customer inquiries about usage levels, bills, and outage status, Ms. Alexander took issue with these savings because service representatives will have more data to evaluate and unless and until the future AMI system is actually connected to the Company's outage management system, there are no benefits to accrue. With regard to "other" benefits in the amount of $2.9 million (NPV), Ms. Alexander testified that PSO provides no basis for the estimated savings in this category and, therefore, they are hypothetical and without justification. Therefore, Ms. Alexander argued that the Commission cannot rely on such estimates in evaluating the cost benefits of PSO's full AMI deployment request.

III. PSO'S ESTIMATES OF ITS AVOIDED CAPACITY ADDITIONS HAVE NO CONNECTION TO AVOIDED COSTS THAT CUSTOMERS WILL ACTUALLY EXPERIENCE AND SHOULD NOT BE RELIED UPON TO SUPPORT THE AMI INVESTMENT

Ms. Alexander took issue with Company's newly found benefit in the amount of Avoided Capacity Additions equal to $113.6 million (NPV) described in Mr. Lewellen's Rebuttal Testimony. She testified that the Company's alleged values associated with its peak load reductions and energy consumption reductions, the methodology assigns a value to these energy and peak load reductions based on what it would cost to construct and operate an

82 MW gas fired generation facility. She testified that PSO did not promise that it [*sic*] would avoid constructing a new 82 MW gas fired generation plant if AMI is deployed and contrary to Mr. Lewellen's assumptions, PSO's most current Integrated Resource Plan (IRP) does not suggest it would meet peak load needs with a gas fired generating facility, but instead contemplates short-term purchased power contracts for any needed capacity and energy in the next 15-years and does not include any analysis of the impact of AMI-enabled demand response programs that are included in this filing.

Ms. Alexander stated that there is no basis for any claim that customers will avoid $113.6 million in costs if these programs operate as predicted. Customers will not see these costs reflected in their rates and bills. In order to be estimates that can be relied upon, the calculation of the avoided capacity and energy costs must reflect needed resources that can be avoided with substitutes in the form of lower consumption and lower peak load reductions, a situation that does not apparently exist for PSO. She also testified that it does not appear defensible to suggest, as PSO apparently does, that the Company's predicted avoided costs can be justified by implementing a very expensive way to achieve efficiency and demand reductions that are not needed in the Company's resource plan.

IV. PSO'S ESTIMATES OF PARTICIPATION RATES AND IMPACTS ASSOCIATED WITH ITS CUSTOMER PROGRAMS SUFFER FROM SIGNIFICANT DEFECTS AND LACK CREDIBILITY.

Normally it would be reasonable to at least start with the assumption that the pilot participation rate will predict the rate of participation for full-scale deployment, Ms. Alexander testified. She further stated that she disagreed with this assumption because the design of these programs differs from those implemented in the pilot program in ways that will necessarily result in lower participation by customers.

She testified that it was not possible in her opinion to assume that the same number of customers that enrolled in the "free" program are going to enroll in the program where the customer must take affirmative action to purchase the thermostat, install the thermostat, maintain the thermostat and its ability to communicate with PSO, and rely entirely on a post-purchase rebate to assist in paying for the time and effort to pursue these entry level obligations. In addition, she testified that PSO failed to include the costs of customer credits for allowing the thermostat to be controlled by PSO during critical peak events ($40 per summer) in its costs for AMI deployment or its NPV analysis. Therefore, she testified that PSO should discount its predicted participation rate and resulting costs and benefits to correct these defects and omissions.

Moreover, Ms. Alexander testified regarding PSO's future plans for a pre pay program. Ms. Alexander testified that such programs are very controversial particularly when they are marketed or offered to low income customers as a means to avoid disconnection of service, late fees, deposit requirements, or other indicia of unaffordable bills. She testified, therefore, her concern with including these alleged benefits for this program at this time are related to the basis for the Company's predicted participation rate and energy impacts for a program that has yet to be defined, proposed, tested, or reviewed.

V. PSO HAS FAILED TO SET FORTH ANY METHODOLOGY TO TRACK AND REPORT BENEFITS THAT IT RELIES UPON TO JUSTIFY THIS INVESTMENT

Ms. Alexander testified that although PSO has committed to track [*sic*] costs incurred, PSO does not make any proposal to track all its alleged and promised benefits as set forth in Mr. Lewellen's Rebuttal Testimony. Ms. Alexander testified that the Company is asking this Commission to approve the investment of a costly project that will increase customer bills for $3 to $4 per month for three years or more without any means to actually document that its promised cost reductions or bill savings will actually occur as predicted. This is not a bargain that ratepayers should accept.

VI. PSO'S COSTS WILL SIGNIFICANTLY EXCEED ITS BENEFITS AND THE SO-CALLED "QUALITATIVE" BENEFITS ARE INSUFFICIENT TO JUSTIFY THIS SIGNIFICANT GAP

Based on Ms. Alexander's analysis, she concluded that:

1. The Company's cost estimates are not reliable because they are not based on any vendor quotes and the results of any bids or requests for proposals. Nor is there any cap or ceiling associated with its cost recovery methodology;

2. The Company's calculation of avoided operational costs and benefits reflect risks and the potential that they are over stated;

3. The Company's calculation of the value of avoided capacity costs is not a benefit that will result in lower customer rates and prices;

4. The Company's reliance on its estimates of participation rates and results for its undefined future Pre Pay Billing program should be rejected as without support and not based on evidence about the nature of the program it will propose, its incremental costs, and the likelihood of its success;

5. The Company's reliance on past participation rates and results for the consumer programs implemented in its pilot program is not reasonable since the design and customer participation costs for those programs have changed; and

6. If, as I propose, the "avoided capacity addition" benefit is eliminated from the Company's cost/benefit calculation, the costs of AMI deployment will exceed the promised benefits by a factor of more than two even if all the other assumptions remain as proposed by the Company (an assumption I do not agree with):

Revenue Requirement:	($176.5 million)
Consumer Programs:	($16.2 million)
Benefits Other than Avoided Capacity	$86.5 million
TOTAL	($106.2 million)
Benefit/Cost Ratio:	0.45

Ms. Alexander also testified that the Company failed to conduct any sensitivity analysis of the key variables reflected in its cost/benefit analysis to determine whether its prediction that benefits will exceed costs is robust. She also testified that this defect is a glaring example of the Company's attempt to [*sic*] gloss over the optimistic assumptions about benefits that it never actually promises to deliver to ratepayers. She also testified that while the Company alleges that these qualitative benefits have been "observed" in the AMI pilot project or other AEP companies and "are generally reported across the utility industry," there are no citations or documents to support this very broad general assertion.

In summation, Ms. Alexander testified that she recommends that PSO's proposal to deploy advanced metering throughout its service territory and recover costs through a Rider should be rejected because PSO's cost/benefit analysis does not support it as a program that will be cost beneficial to customers and PSO fails to provide evidence that such investment will lead to benefits in either operational expenses or the price of electricity for customers. My recommendation is based on the evidence set forth in detail in my testimony, and reflects the following significant conclusions:

(1) PSO has failed to include all relevant costs in its cost/benefit analysis.

(2) PSO has included a significant level of benefits and benefit values that are not defensible due to their unrealistic assumptions about their predicted impacts due to PSO's AMI deployment proposal.

(3) PSO has used a methodology to calculate [sic] future benefits due to avoided peak load demand and energy conservation that has no apparent relationship to its own Integrated Resource Plan or its future capacity and energy needs.

(4) PSO has relied on [sic] a significant level of benefits from a future and potentially controversial Pre Pay service program that is not yet developed or publicly available for review at this time.

(5) PSO's AMI costs are highly likely to significantly exceed any reasonable level of benefits that will occur as a result of this investment.

(6) PSO has not provided any methodology to ensure that its promised benefits will be tracked and actually proven to be delivered to its customers in return for this expensive project.

(7) PSO's proposed method for cost recovery shifts almost all the risks associated with the accuracy of its estimated cost and benefits to customers.

<u>Summary of the Responsive and Rate Design Testimony of Edwin C. Farrar</u>

Mr. Edwin C. Farrar pre-filed responsive testimony and rate design testimony on behalf of the Attorney General of the State of Oklahoma. He testified as to his educational and professional background as a Certified Public Accountant. He has testified previously before the Oklahoma Corporation Commission and his qualifications as an expert have been accepted. Mr. Farrar recommended certain adjustments to the cost of capital, to rate base, to the operating income statement of PSO, and to rate design issues.

On the cost of capital issue, Mr. Farrar agreed with PSO's witness Dr. Murry that the CAPM analysis cannot represent the market-determined cost of equity under recent market conditions. Mr. Farrar recommended that the CAPM analysis be disregarded. Mr. Farrar stated that the forecasted returns identified by Dr. Murry on exhibit DAM-17 represented high-end forecasts and that the combination of high-end and low-end forecasts produced a much lower result. Mr. Farrar performed [*sic*] a DCF analysis using data from independent and unbiased sources that produced results comparable to the DCF analysis prepared by Dr. Murry. Mr. Farrar recommended that the return on equity be set at 9.19% based on returns of comparable companies in his DCF analysis.

Mr. Farrar recommended that rate base be updated for known and measurable changes known to occur six months after the end of the test year as required by statute, to January 31, 2014. These adjustments included plant in service, construction work in progress, accumulated depreciation, fuel and materials and supplies inventory, and accumulated deferred income taxes.

Mr. Farrar recommended several adjustments to operating expenses including payroll, incentive compensation, nonqualified retirement plans, service company expenses, property taxes, the depreciation study, and the requested riders. He testified that payroll related expenses should be adjusted to levels at January 31, 2014, and that the Company included cost increases beyond that date. Mr. Farrar explained that including selective cost increases beyond the six month statutory update period would unfairly reflect cost increases and ignore offsetting cost decreases. Mr. Farrar recommended the annualization of payroll expenses at January 31, 2014, which reduces PSO's requested jurisdictional payroll cost by $725,117 and the related payroll taxes by $52,703. Mr. Farrar also recommended that the Commission adopt the adjustments they have made in previous rate cases to incentive compensation programs that are of limited benefit to ratepayers. Mr. Farrar testified that a portion of this form of compensation rewards employees for high Company earnings and the plan included limited benefits for ratepayers. Mr. Farrar recommended the Commission exclude one half of the annual incentive plan costs as they have in recent rate cases. Mr. Farrar's recommended adjustment reduces the jurisdictional incentive compensation costs of the Company by $4,114,848 and it reduces the related payroll tax expense by an additional $299,073. Mr. Farrar also recommended the Commission follow its policy of excluding all long-term incentive compensation from the revenue requirement because these plans are almost always entirely financial in nature, designed to increase the company's earnings regardless of how that is achieved. Mr. Farrar recommended an adjustment to exclude the cost of the long-term incentive plans from rates which reduces the jurisdictional revenue requirement by $3,551,015. Mr. Farrar also testified that the cost of the non-qualified pension plans be excluded from rates because this type of indirect compensation for highly paid executives is unnecessary and expensive. The adjustment to exclude the non-qualified pension costs from rates reduces the Oklahoma retail revenue requirement by $90,568. Mr. Farrar discussed PSO's headcount adjustment to the AEPSC expenses. This adjustment was not supported by work papers. Mr. Farrar performed [*sic*] analysis of AEPSC employee levels and payroll costs and found that both had declined during and after the test year. Mr. Farrar recommended that this adjustment be disallowed and the requested AEPSC costs be reduced by $798,078 jurisdictionally. Mr. Farrar testified that ad valorem tax expense should be updated to January 31, 2014, as required by statute and consistent with the update of plant in service to that date. This adjustment increases the jurisdictional ad valorem taxes by $89,857. Mr. Farrar recommended that the increase in depreciation rates requested by the Company not be approved based on his review of the studies prepared by Staff and the OIEC. Mr. Farrar recommended that some of the Riders requested by PSO not be approved because they reduce the pressure for the Company to keep costs down. Mr. Farrar recommended that riders be limited to circumstances where they are most necessary. Those circumstances include when a cost is unquestionably necessary for the operation of the utility system, when the cost is not controllable by the utility, when the cost is uncertain, and when the cost is sufficiently large to impair the utilities ability to earn its authorized return. Mr. Farrar recommended that the vegetation management/undergrounding rider be eliminated and the costs rolled into base rates. Mr. Farrar also recommended the request for the AMI rider also be denied and the proposed 2014 level of expenses be included in base rates. Mr. Farrar testified that PSO removed the test year cost for the vegetation management program with Adjustment H 2-37 and he recommended that the adjustment be reversed and the $15,373,192 of jurisdictional cost be restored to the revenue requirement. Mr. Farrar further testified that the adjustment to include the AMI costs in the revenue requirement increases the jurisdictional Plant in Service by $16,020,263, Accumulated Depreciation by $2,220,725, O&M expenses by $1,524,173 [*sic*], and Depreciation Expense by $2,331,594.

Mr. Farrar filed rate design testimony recommending that no rate increase be approved, that PSO's request to increase the residential customer charge be denied and that any rate decrease be applied proportionally between the customer charge and the energy charges.

<u>AARP Testimony Summaries of the Responsive and Rebuttal Testimony of Barbara R. Alexander Filed on April 23, 2014 and May 29, 2014, Respectively</u>

<u>SUMMARY OF RESPONSIVE TESTIMONY OF BARBARA R. ALEXANDER FILED ON BEHALF OF AARP ON APRIL 23, 2014</u>

Ms. Barbara R. Alexander, a Consumer Affairs Consultant, filed responsive testimony on behalf of AARP on April 23, 2014. Ms. Alexander's consulting practice focuses on regulatory and statutory policies concerning consumer protection, service quality and reliability of service, customer service, and low-income issues associated with both regulated utilities and retail competition markets. She has testified in rate cases, rulemaking proceedings, and investigations before over 15 U.S. and Canadian regulators.

Ms. Alexander's clients include the state ratepayer public advocate offices in Massachusetts, Illinois, Pennsylvania, Washington, Maryland, Maine, Arkansas, and West Virginia, as well as AARP in many states (Montana, New Jersey, Maine, Mississippi, Ohio, Virginia, Illinois, Maryland, Oklahoma, and the District of Columbia).

Ms. Alexander stated that PSO has filed for a $45 million base rate increase that would, if approved, raise the average customer bill using 1,000 kWh per month by $4 per month in the first year or $48 per year, reflecting a 4.69% increase from current rates and riders. In addition to this increase, PSO's request for the full deployment of smart meters has a [sic] very large impact. The publicized base rate increase amount does not include the costs beyond the initial rate effective year ($1.12 per month or $13.44 annually) for full deployment of an advanced metering system that PSO seeks to recover through a surcharge mechanism that will increase monthly bills by $2.54 per month ($30.48 annually) in 2016, and $4.14 per month ($49.68 annually) in 2017. As a result, the actual bill increase will be much higher than emphasized by the Company in its press releases and public information on its website. She testified that lower income customers must allocate a much higher percentage of household income for essential energy services compared to middle and higher income customers. A 4-person household with income at the poverty level in 2012 of $23,492 would have to pay 4.5% of their annual income for the average residential PSO electric bill if the base rate increase is approved. This does not include the additional costs associated with PSO's proposed advanced metering rider that will be charged after the initial rate effective year. For example, *by 2017 the impact of the advanced metering rider will more than double the base rate increase of $4 per month to $8.14 per month.* Of course, this percentage of household income dramatically increases for families with even lower income or who have higher usage levels than average due to the conditions of their housing and the older age of their appliances. Finally, this percentage does not reflect other energy needs for home heating, such as natural gas.

Ms. Alexander's responsive testimony addresses: (1) the company's request for full-scale smart meter deployment and the request for a rider to recovery costs; (2) disconnection practices; (3) PSO's use of riders and need for base rate cases to evaluate prudent and used and useful investments; (4) PSO's request to increase the monthly fixed customer charge; and (5) PSO's lack of any low income bill payment assistance program.

1. PSO'S REQUEST FOR APPROVAL OF FULL DEPLOYMENT AND COST RECOVERY FOR AN ADVANCED METERING SYSTEM SHOULD BE REJECTED AT THIS TIME

Ms. Alexander recommends the Company's proposal to deploy advanced metering throughout its service territory and recover costs through a rider should be rejected for many reasons. First, PSO's testimony fails to include any calculation of many of the benefits that it alleges will occur as a result of the full deployment of AMI and did not include a cost/benefit analysis over the life of the project. Second, the programs that PSO implemented for its approved pilot program will be significantly altered for the full deployment of AMI and even the pilot program results raise significant questions about the customer benefits of AMI. Third, PSO's own surveys clearly documented that the primary motivation of customers to participate in customer programs enabled by AMI is to reduce their electric bill, but PSO has not evaluated the bill impacts of its altered customer programs or the impact of the additional costs for AMI that it seeks to impose with its proposed AMI Rider which will substantially reduce the potential for customer savings. Finally, PSO's own internal evaluation of the costs and benefits of AMI deployment obtained through discovery was labeled "preliminary," but does document that the program is not cost beneficial.

PSO estimates it will cost $132.9 million in capital costs and $15.450 million in operations and maintenance (O&M) costs over three years. The proposed revenue requirement for this system is $4 million in 2014, $16.8 million in 2015, and $27.7 million in 2016. PSO seeks to recover these costs through a surcharge or rider. While the Company's filing emphasizes the first year cost impact of the Rider for residential customers at $1.12 per month ($13.44 annually) in its filing, PSO did not provide estimated bill impacts for the second and third years of the cost recovery mechanism until requested to do so in discovery. PSO's residential customers will incur an additional bill charge of $2.54 per month ($30.48 annually) in 2016, and $4.14 per month ($49.68 annually) in 2017.

In addition to the costs above, PSO estimates that the following two additional cost categories will be imposed on customers: (1) the unrecovered book value of its current working metering system estimated at $64.7 million; and (2) $2.75 million for a three-year amortization of severance/retention payments to employees.

Ms. Alexander testified that enrollment in [*sic*] PSO's pilot customer programs is very low. The Smart Shift program had only 222 participants in 2012 and 768 in 2013, 2.4% of the smart meter enabled customers. The Smart Shift Plus program had an even lower enrollment, 51 in 2012 and 76 in 2013. Furthermore, both programs experienced a drop-out rate during the program year and PSO has not evaluated why those customers dropped out or what programs features these customers found undesirable or whether those customers dropped out due to experiencing higher bills. As to usage of the PSO website, Ms. Alexander testified that PSO has found that only 625 customers accessed the web portal in 2013.

The survey data provided by PSO clearly documents that the vast majority of customers would be interested in these programs *only* if they resulted in lower bills. Given the pilot results, the incremental costs associated with the proposed Rider, there is no evidence in this record that shows or would allow any determination to be made that bills for the PSO ratepayers would be lower or that overall costs for generation supply would be lower with the full implementation of the advanced metering system.

Ms. Alexander testified that PSO claims that this advanced metering system will result in a "host" of benefits. However, none of these benefits were described in any specificity and none of them were calculated in terms of reduced costs to ratepayers to offset the costs to ratepayers of the advanced metering system. As a result, PSO is asking customers to pay for almost the entire estimated costs for this technology without agreeing to assume any risk that its alleged benefits will occur or how these hypothetical benefits will be reflected in its rate [*sic*] recovery methodology beyond the $5 million in guaranteed savings relating to operational costs, primarily due to the elimination of jobs associated with meter reading and meter related field activities.

Ms. Alexander also testified that the Company has not proposed any methodology or specific metrics to track costs and benefits for its proposed advanced metering project to ensure that its alleged benefits will in fact be delivered in a manner that would allow the Commission to determine that the costs were prudently incurred. As a result, she testified that there is no basis on which the Commission could ever determine that the proposed investment was prudent or that it was implemented in a cost effective manner.

As a result of her analysis of the Company's information, she recommends that the Company's proposal to deploy and seek recovery of costs for an advanced metering system should be denied. Given the relatively poor documented benefits from the customer pricing programs, the proposed changes to those programs, and the lack of any factual analysis of costs and benefits, this system has not been demonstrated to be prudent and should not be reflected [*sic*] in rates.

Ms. Alexander recommends that the Commission require the Company to develop and explore improvements in education and outreach based upon the pilot survey responses and program evaluation. After the implementation of the revised programs and outreach activities, Ms. Alexander recommends that the Commission require PSO to conduct an evaluation of the revised programs and submit a report annually for at least two years to determine whether PSO's changes to these pilot programs were effective.

In addition, Ms. Alexander testified that the Commission should reject PSO's attempts to include the costs of its Distribution Automation and the Volt/Var projects in base rates because of the failure after several years of funding to yield any evaluation or results that suggest such programs will provide the benefits that were originally anticipated.

2. THE COMMISSION SHOULD REVISIT ITS PRIOR WAIVER THAT ELIMINATES THE PREMISE VISIT REQUIRED FOR DISCONNECTION FOR NONPAYMENT FOR RESIDENTIAL CUSTOMERS

A number of states with advanced metering deployment have retained important consumer protections related to disconnection for nonpayment for residential customers, such as premise visits, attempt to contact, and accepting payment at the premises. PSO has failed to properly track for analysis the impact of disconnection as a part of its pilot advanced metering program.

Ms. Alexander recommends that the Commission require PSO to track the incidence of disconnection of service for nonpayment of residential advanced metered customers so that such information can distinguish the presence of an advanced meter and report this information quarterly to the Commission and other interested parties. Furthermore, Ms. Alexander recommends that the Commission require PSO to provide basic information on customers with advanced meters with regard to late payment, payment plans, and overdue bill amounts compared to other residential customers in order to determine if PSO's attempts to contact such customers and avoid disconnection of service is sufficient in light of the elimination of the premise visit.

3. THE COMMISSION SHOULD TAKE A STEP BACK FROM APPROVING SURCHARGES AND RIDERS AND RELY ON TRADITIONAL BASE RATE PROCEEDINGS TO DETERMINE PRUDENCY AND COST RECOVERY

A surcharge is an additional fee imposed on a ratepayer's utility bill in addition to the base rate charge for utility service. In the past, surcharges were only approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if not addressed outside of a base rate case, could threaten to harm a utility's financial health. More recently, utilities have requested surcharge rate mechanisms as a means to accelerate the recovery of a variety of costs, many of which are not volatile or uncontrollable, thus avoiding the obligation to implement investments and seek recovery of costs in a rate case where prudency can be reviewed and determined.

A utility that is allowed to recover costs through a surcharge is able to typically obtain a near real-time recovery of its costs and a rate of return on capital expenditures without any documentation that the costs have resulted in the benefits that were promised with the investment or any documentation that the utility [*sic*] has managed its projects and costs in a manner to reduce costs and implement cost effective solutions.

Where costs are transferred from a surcharge cost recovery methodology to base rates, I recommend that the project or investment first be evaluated carefully to determine that the underlying program has been implemented in a cost effective and efficient manner and that the current costs being recovered in the surcharge or rider properly represent a reasonable level of recurring costs that should be included in a revenue requirement going forward.

Ms. Alexander testified that the Commission should generally reject proposals for riders and surcharges and, properly place cost recovery into future base rates, but only after carefully evaluating PSO's costs prior to including the proper level of expenses for these costs.

Ms. Alexander testified that should the Commission allow PSO to recover advanced metering project costs in the future, she would recommend that such rate recovery not be implemented through a surcharge or rider, but rather considered in the context of a traditional base rate case where all costs and benefits can be identified and evaluated prior to allowing cost recovery or a finding of prudency.

Ms. Alexander recommends that the Commission reject PSO's advanced metering cost recovery mechanism and that if any additional "smart grid" related investments are proposed by PSO, the Company should be required to implement those programs and investments it determines to be appropriate and then seek recovery of costs in a future rate case at which time the prudence of those costs and investments can be determined prior to allowing cost recovery in rates.

<u>4. PSO'S PROPOSAL TO INCREASE THE RESIDENTIAL FIXED CUSTOMER CHARGE SHOULD BE REJECTED</u>

PSO has proposed that the residential customer monthly charge should be increased from \$16.16 to \$20.00. PSO has not justified its proposal with any analysis other than to claim that their distribution costs are "fixed" in nature. This would put PSO's customer charge well above [*sic*] OG&E's fixed charge of \$13.00 per month. Ms. Alexander recommends that the Commission reject PSO's proposal to increase the monthly fixed customer charge for residential customers because PSO has failed to provide evidence of increases in its fixed charges to support the proposed increase. Furthermore, Ms. Alexander testified that an increase in fixed monthly customer charges results in higher bills for low usage customers and does not send the proper cost signal to stimulate investments in efficiency and usage reduction.

<u>5. PSO SHOULD BE REQUIRED TO IMPLEMENT A LOW INCOME BILL PAYMENT ASSISTANCE PROGRAM, SIMILAR TO THAT IN EFFECT FOR OKLAHOMA GAS & ELECTRIC</u>

Ms. Alexander recommends the Commission require PSO to implement a low income bill payment assistance program similar to that provided to low income customers by Oklahoma Gas & Electric Company (OG&E), which provides qualified customers with a monthly bill credit of \$10.00. Ms. Alexander recommends that PSO be directed to develop a tariff similar to that of OG&E and provide an estimate of the costs it would incur to implement this same program using LIHEAP eligibility as the definition of the group of customers that would receive this benefit.

In summary, Ms. Alexander on behalf of AARP, recommends that the Commission order the following changes to the Company's proposals in this Cause:

1. Ms. Alexander recommends the Company's proposal to deploy advanced metering throughout its service territory and recover costs through a rider should be rejected for many reasons. First, PSO's testimony fails to include any calculation of many of the benefits that it alleges will occur as a result of the full deployment of AMI and did not include a cost/benefit analysis over the life of the project. Second, the programs that PSO

implemented for its approved pilot program will be significantly altered for the full deployment of AMI and even the pilot program results raise significant questions about the customer benefits of AMI. Third, PSO's own surveys clearly documented that the primary motivation of customers to participate in customer programs enabled by AMI is to reduce their electric bill, but PSO has not evaluated the bill impacts of its altered customer programs or the impact of the additional costs for AMI that it seeks to impose with its proposed AMI Rider which will substantially reduce the potential for customer savings. Finally, PSO's own internal evaluation of the costs and benefits of AMI deployment obtained through discovery was labeled "preliminary," but does document that the program is not cost beneficial.

2. The Commission should reconsider its previous order that grants a waiver to PSO to implement remote disconnection for nonpayment by residential customers and eliminate the required premise visit and associated notices. At a minimum, PSO should be required to track for analysis the impact of such waiver as a part of its pilot advanced metering program. As a result of PSO's inability to provide disconnection information that distinguishes advanced metering from traditional metering customers, the Commission and parties, including AARP, are denied the ability to access the impact of the waiver on the health, safety and wellbeing of customers.

3. The Commission should generally reject proposals for riders and surcharges. Where current riders are eliminated and proposed to be included in base rates, the Commission should carefully evaluate and potentially audit PSO's costs prior to including the proper level of expenses for these costs in base rates.

4. The Company's proposal to increase the monthly fixed customer charge for residential customers should be rejected because PSO has failed to provide evidence of increases in its fixed charges to support the proposed increase and because of the adverse impact of this rate change on lower usage customers.

5. The Commission should require PSO to implement a low income bill payment assistance program similar to that provided to low income customers by Oklahoma Gas & Electric Company.

SUMMARY OF THE REBUTTAL TESTIMONY OF BARBARA R. ALEXANDER FILED ON BEHALF OF AARP ON MAY 29, 2014

Vegetation Management Costs and Rider Recovery

Ms. Alexander filed rebuttal testimony regarding the treatment of PSO's recovery of vegetation management costs, which are currently collected through a combination of base rates and through the System Reliability Rider known as the SSR Rider. PSO filed the testimony of Mr. Baker and PUD Staff filed testimony of Mr. Robert Thompson on this issue.

Although Ms. Alexander testified that she generally supports the elimination of riders and surcharges and the inclusion of ongoing utility costs and expenses in base rates, she testified to her significant concerns with the recommendation of PUD Staff that $14.9 million currently collected through the rider be included into base rates, that already collects approximately $5 million, for an annual recovery of approximately $20 million from ratepayers *without further review and analysis.*

Ms. Alexander recommends the Commission not approve an additional $14.9 million in base rates at this time and recommends the Commission undertake an audit or other focused examination of the expenditures, both capital and O&M, currently being collected in this Rider, along with the $5 million already included and recovered through base rates, and affirmatively decide whether a recovery of [*sic*] such amounts in base rates is appropriate in light of the original and amended purposes of this Rider.

Ms. Alexander reiterates her position that "Where costs are transferred from a surcharge cost recovery methodology to base rates, she recommended [*sic*] that the project or investment first be evaluated carefully to determine that the underlying program has been implemented in a cost effective and efficient manner and that the current costs being recovered in the surcharge or rider properly represent a reasonable level of recurring costs that should be included in a revenue requirement going forward." [Alexander Resp. Test. pp. 33-34.]

Because in this case, there is no record evidence to support the proper level of costs, the purpose of the costs, or whether this $20 million represents a reasonable amount to be included in the revenue requirement going forward, it should not be moved into base rate recovery and should be subject to an audit by this Commission.

<u>Summary Testimony of Mark E. Garrett</u>

<u>I. Revenue Requirement Responsive Testimony</u>

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 <u>rate decrease</u> of $22,196,431, as shown below:

Rate Increase Proposed by PSO	$ 37,305,012
OIEC Adjustments	<u>$(59,501,443)</u>
Decrease Proposed by OIEC	**<u>$(22,196,431)</u>**

1. **<u>Plant in Service and Accumulated Depreciation</u>**. Pursuant to Title 17 § 284, Plant in Service and Accumulated Depreciation accounts have been updated to January 31, 2014, to give effect to known and measurable changes that occur within six months of test year end. The Company's requested level for plant investment includes actual Plant in Service balances at test year end, <u>plus the cost of construction projects expected to be completed</u>

and in service within six months after test year end. My adjustment picks up the actual plant balances at January 31, 2014. Thus, all plant construction actually completed within six months of test year end is properly included in rate base. Also, all offsetting decreases in the plant investment levels are recognized as well. This approach has been accepted by the Commission in several prior cases including: Cause No. PUD 200400610, Cause No. PUD 200500151, Cause Nos. PUD 200600285, and PUD 200800144. In each of those cases, projects still in the Construction Work in Progress ("CWIP") accounts at that time were properly excluded.

In completing the 6-month updates, three additional adjustments are required to adjust AMI meter costs and related Intangible Plant on AMI meters. In its Application, PSO removed these costs from Plant in Service balance and requested that these costs be recovered through a rider mechanism. In my rate design testimony, I recommend that PSO's requested rider recovery mechanism for AMI should not be approved. Although I do not support using a rider mechanism to recover these costs, I do recommend that AMI costs incurred as of January 31, 2014 related to AMI Meters and AMI Intangible Plant be included in rate base. Therefore, I have made an adjustment to include these costs in PSO's Plant in Service as of January 31, 2014. Similarly, PSO removed from its Accumulated Depreciation account the corresponding accumulated depreciation associated with AMI Meters. I have reinstated these amounts to the January 31, 2014 balances. The OIEC adjustments result in a net increase of **$71,663,965** in rate base.

2. **<u>Accumulated Deferred Income Tax ("ADIT")</u>**. The ADIT balances are adjusted to the January 31, 2014, 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, as requested by the Company in this cause, offsetting decreases in the investment levels related to Plant in Service such as Accumulated Depreciation and Accumulated Deferred Income Tax must also be recognized. This adjustment has been consistently recognized and accepted by the Commission in rate case proceedings after the 6-month rule was enacted. In addition to the 6-month update, the ADIT account balance must be adjusted to add back the ADIT associated with both the AMI Meter costs and the AMI Intangible Plant costs which have been reinstated in Plant in Service. The OIEC net adjustment to ADIT is **$20,309,287**.

3. **<u>Other Rate Base Adjustments</u>.** I have updated the fuel inventory level to reflect the actual fuel inventory level at January 31, 2014, 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. I propose using the actual level at January 31, 2014, because these inventory levels decreased after the end of the test year and did not fluctuate much during the 6-month post test year period. I have also updated the prepayment balance to reflect the actual level at January 31, 2014. The Company proposed using a 13-month average at test year end. I propose using the actual level at January 31, 2014, because prepayment levels decreased after test year end and have remained at this lower level.

I also propose adjustments for 2013 Storm Costs. The Company included a regulatory asset for the July 2013 storm costs in the amount of $10,000,000, seeking a four-year amortization of these costs in base rates. Although I am not opposing the base rate recovery of these costs, I do not believe the deferred costs should earn a return while they are being recovered. The utility has effectively shed all of its rate-recovery risk associated with storm losses through the deferred accounting treatment. It should not also be allowed to earn a profit return on these costs during the recovery process. The other rate base adjustments for fuel inventory, prepayments and storm costs result in a net decrease to rate base in the amount of **$17,990,771.**

4. **Prepaid Pension Asset.** I propose reducing PSO's rate base by the balance in the prepaid pension account and increasing [*sic*] 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 6.5%. This is the amount by which the excess contributions reduce Net Periodic Pension Costs, the amount included in rates. In effect, the net benefit to ratepayers from excess contributions is 6.5%. Thus, I am proposing that ratepayers pay a return on these costs that is no greater than the benefit they receive.

The balance in the prepaid pension account represents the accumulated difference between (1) the Statement of Financial Accounting Standards No. 87 ("SFAS 87") calculated pension costs each year (the amount included in rates); and (2) the actual contributions made by the Company to the pension fund. When there is a debit balance in the account, as is the case here, the Company has been contributing more to the fund than its SFAS 87 calculated cost levels. PSO's contributions in excess of the SFAS 87 cost levels were generally discretionary payments. These payments, however, do generally tend to increase the Company's pension asset, which tends to decrease future funding needed to cover the pension liability.

I recommend a return equal to the *expected return* because this is the amount by which ratepayers benefit from the contributions. Also, a higher full rate base return includes a substantial profit component that the lower *expected* return does not include. Since the contributions to the pension fund above the SFAS 87 expense levels are discretionary contributions, ratepayers should not be required to pay an amount that is greater than the benefit they receive from these contributions, and the Company should not be allowed to earn a profit on the excess discretionary contributions it makes to the fund. This treatment has been accepted by the Commission in the past including: Cause No. PUD 910001190 [*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.

The following 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 by an amount equal to the *expected* return on the prepaid balance. The necessary adjustments are set forth in the table below:

OIEC Adjustments to Prepaid Pension Account		
1	Adjustment to Remove Prepaid Pension Balance in Rate Base	($104,227,255)
2	Adjustment to Remove Prepaid Pensions ADIT from Rate Base	$ 36,479,539
3	Adjust to Include Expected Return on Prepaid Pensions [Net Balance x Expected Return Rate: (67,747,716 x 6.50%)]	$ 4,403,602

The first two adjustments shown in the table 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 **$3,188,207.**

5. **<u>Capitalized Incentive Compensation in Rate Base</u>**. 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 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 $41,831,824 of capitalized incentive compensation, which includes $39,048,124 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, for a total adjustment of $22,307,762. This treatment is consistent with the Commission's prior treatment of PSO's incentive plans in the prior litigated cases of PUD 200600285 and PUD 200800144.

6. **<u>Annual Incentive Compensation Expense</u>**. 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 is clear that more than 50% 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 $8,236,889 by 50%, or **$4,118,445**.

   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% for amounts tied to financial performance. The Commission also reduced OG&E's annual incentive plan costs by 50% in OG&E's last litigated rate case, PUD 200500051. PSO's 2012 Annual Compensation Plans are heavily dependent on financial performance measures, primarily as a result of the EPS Modifier. PSO's Incentive Compensation Plan Measures and Weights sets forth the various financial and nonfinancial categories the Company evaluates in its incentive compensation program. However, the Company admits the funding of the incentive compensation is contingent on meeting the earnings per share (EPS) targets.

In other words, even though the Company's performance measures include both financial and non-financial factors, the actual *funding* trigger for incentive compensation is the EPS Modifier, which is directly tied to the financial performance of the Company. For example, under the EPS funding mechanism, 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 EPS 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 will be paid. According to the Company's schedules, the EPS Modifier allocates incentive funding "based on the earnings produced for shareholders" and it "ensures that payouts are always commensurate with AEP's EPS performance."

Many jurisdictions exclude some or all of the cost of incentive plans which are tied to financial performance measures (are excluded for ratemaking purposes). [sic] 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 will not continue to offer financial-based incentives. They do. When a financial-based incentive package is properly constructed, however, there will be ample increased earnings to fund these payments. Thus, ratepayers do not need to subsidize incentive compensation plans designed to enhance financial performance.

The results of Garrett Group's Incentive Compensation Survey of the 24 Western States taken in 2007, updated in 2011, shows that 19 of the 24 states surveyed follow the financial-performance rule, where incentive payments associated with financial performance are excluded from rates. Three states disallow incentive pay using other criteria, and two states do not have stated regulation or policy for the treatment of incentive compensation. None of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule.

Western States that follow the Financial Performance Rule include:
Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, Oklahoma, Oregon, S. Dakota, Texas, Utah, Washington, Wyoming.

States that use another approach: Alaska, Iowa, Montana, N. Dakota.

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. In my opinion, utilities continue to tie incentive payments to financial performance because doing so achieves the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share (EPS). However, since the utility retains the increased earnings these plans help achieve, payments for the plans should be made from a portion of these increased earnings. Thus, properly designed incentive compensation plans need not be subsidized by ratepayers.

Under the Company's Plan, annual payment is uncertain. The EPS 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 overall compensation levels based upon 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 all of 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.

AEPSC's plans are all weighted heavily toward company goals and financial performance measures in particular, much like the plan at the operating company level discussed above. Although some of the AEPSC plans show some weighting toward customer satisfaction, the "customers" AEPSC serves are generally the AEP affiliated companies and the employees of these companies, not actual utility customers. Further, all of the AEP plans are limited by the *EPS Modifier* which operates to ensure that incentive payments are not made at the expense of reaching AEP's EPS objectives.

I recommend 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, and in particular, because the EPS Modifier effectively retains the incentive money for shareholders to the extent shareholder value objectives were not met each year. However, if from a policy perspective the Commission wants to encourage a focus on customer concerns, the Commission could include that portion of the plan costs that purports to be representative of customer service and reliability goals. Overall, I believe no more than 50% inclusion in rates for these plans would be appropriate.

In my view, AEP will not be financially harmed if incentive compensation payments are excluded. Its incentive compensation payments are discretionary payments, limited by the Company's *EPS Modifier*. The *EPS Modifier* 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. I note that several states (Arizona, Arkansas, Oregon and Kansas) similarly use a 50/50 sharing for compensation plans that contain both financial and operational measures.

PSO's annual Incentive Plan Payments in pro forma expense is $8,239,889. I propose a 50% disallowance, for an adjustment of $ 4,118,445. In addition, I propose an adjustment to remove labor attendant costs associated with the 50% disallowance of short term incentives in the amount of **$227,156**.

7. **<u>Long-term Executive Stock Incentive Expense</u>**. Senior Managers of the Company provide 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 which are equally weighted between 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 where 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. It has been my experience that 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 is done to further align the interest of the employee with those of the shareholder. Since the compensation of the employee is tied over a long period of time to the company's stock price, it becomes in the best interest of the employee to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interest of the shareholders first.

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 <u>not allowed</u> in most states. In the synopsis of the incentive survey results from each state that was included in the prior section of this testimony, the treatment of executive incentives in each state was underlined. According to the survey, the following western states <u>exclude</u> all or virtually all executive incentive pay: Oregon, California, Nevada, Idaho, Utah, South Dakota, Oklahoma, Wyoming, North Dakota, Missouri, Arkansas, Louisiana and Minnesota. Other states, like Washington, Missouri and Texas, apply the *financial performance* rule, which has the affect of excluding executive incentives, especially stock-based awards.

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 **$3,554,117**.

8. **<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. Benefits payable under these supplemental plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $255,000 for 2013. Retirement benefits on compensation levels in excess of the $255,000 limitation 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 was $359,450.

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. Because officers of any corporation have a duty of loyalty to the corporation, these individuals are required to put the interest of the company first. This creates a situation where not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. 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. 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 **$359,450.**

9. **<u>Payroll Cost Annualization at 6-Month Cut-Off.</u>** PSO's proposed payroll adjustment contains two major components: (1) an annualization of payroll levels at test year end, July 31, 2013, and (2) an increase for post-test year pay raises, calculated by multiplying payroll costs times the nominal rate of the pay raise. PSO's adjustment included raises awarded shortly after test year end and much larger projected raises that might be implemented by April 2014, a full eight months after the test year end. PSO's adjustment results in a net requested increase to payroll of $2,447,734 on a total company basis.

In Oklahoma, the Commission is required by law (Title 17 § 284) to give effect to known and measurable changes that occur within six months of test year end. In this application, the six month cut-off period for post-test year adjustments is January 31, 2014. A payroll annualization at, or near, January 31, 2014 would include all changes to payroll that have occurred by that time. By contrast, the Company's proposed adjustment, which annualizes payroll at test year end, and then proposes *to increase* payroll expense based on the nominal amount of pay raises that might be awarded well after test year end, is not an accurate approach. The Company's method assumes that post test year pay raises increase payroll expense by the same percentage amount as the pay raise. This is not a valid assumption. The Company's approach fails to consider that other events occurring during the same time period may decrease payroll levels by as much or even greater amounts.

The Company's adjustment annualized labor at January 31, 2014, but it also included additional pay raises projected to occur beyond the January 31 cut-off. When the additional pay raises beyond the 6-month cut-off are removed, the actual annualized payroll at January 31, 2014 is $74,949,635. When that amount is multiplied by the payroll expense factor of 70.98%, a total Company payroll expense of $53,199,251 is produced, which is $725,117 lower than the pro forma payroll level requested by the Company. I recommend that PSO's requested payroll cost be reduced by $725,117 to reflect the annualized cost at January 31, 2014. I also recommend that payroll tax expense be reduced by $52,703.

10. **AEPSC Labor Costs at 6-Month Cut-off**. The Company has requested an increase of $798,429 for AEPSC Regular Payroll charges to PSO. I reviewed the AEPSC Payroll charged by pay period from August 2013 through January 2014, and determined that the regular payroll charges trended significantly lower over this time period. Rather than justifying an increase for ratemaking purposes as the Company proposes, it appears the payroll levels at the six month cut-off should be annualized, and an adjustment should be made to decrease the AEPSC payroll charged to PSO for ratemaking purposes. I performed three alternative methods to annualize the AEPSC payroll data. First, I annualized the one month payroll data for the month of January 2014. Based on this calculation the net decrease to AEPSC payroll would be $9,323,777. Next, I annualized the two-month period of December 2013-January 2014, which yielded a net decrease of $7,321,001. Finally, I annualized the three-month period from November 2013-January 2014, which yielded a net decrease of $3,110,579. Each of the annualization scenarios demonstrated a significant drop in AEPSC payroll charges and any of the three methods could be used to establish the ongoing AEPSC charges allowed for ratemaking purposes. However, to be conservative, I recommend the method resulting in the lowest decrease, which is the third scenario, the annualization of the quarter ended January 31, 2014. After reversing PSO's requested increase, the resulting net decrease in AEPSC payroll charges is **$3,110,579**. Based upon this decrease in AEPSC payroll charges, a corresponding payroll tax adjustment is needed to reduce payroll taxes by **$226,139**.

11. **Rate Case Expense**. The Company seeks to recover estimated rate case costs in this case of $750,000. To calculate its pro forma adjustment, the Company reduces the total estimated rate case costs of $750,000 by $248,367 of over-recovered rate case costs from the last rate case (PUD 201000050), and then amortizes the remaining balance of $491,633 over an 18-month amortization period to arrive at its recommended adjustment of $327,755. The problem with the Company's adjustment is that, by the time new rates go into effect in this case the over-recoveries from the last case will have grown by another year which is not reflected in the Company's calculation. The amount the Company will recover from August 2013 through July 2014 is an additional $428,435, which will be sufficient to recover most of the Company's estimated costs in this case.

    In other words, the amount embedded in rates in the Company's last rate case will recover all of the costs from the prior case and most of the costs from this case by the time new rates go into effect. In fact, all but $63,198 of the Company's original *estimated* total rate case costs will be recovered before the new rate period begins. Moreover, in my view, the Company's estimated rate case costs are overstated. First, the Company's original estimate includes $200,000 for a Return on Equity ("ROE") witness. The market price for an ROE witness is between $25,000 and $50,000. Based on this inflated line item alone, it appears the Company's original estimated rate case costs are overstated. Ratepayers should not be burdened with unreasonably overstated fees for the Company's ROE witness. Second, as of February 2014, the Company had only spent $281,000 of its original $750,000 estimate. It does not appear the Company could, or should, spend the full amount of original estimate by the end of this case. Because the Company's original number should be lower by *at least* $125,000, the over-recoveries from the prior case will completely cover the costs from this case by the time new rates go into effect. There is no need to include any amount for rate case costs because the Company will have fully recovered its costs for this case by the time new rates go into effect. I recommend that the Company's pro forma adjustment of **$327,755** be reversed.

12. **<u>Depreciation Expense</u>**. In this application, PSO proposes to increase its revenue requirement by $30,505,024.00 to reflect the Company's higher plant balances and new proposed higher depreciation rates. OIEC's recommendations regarding depreciation rates are set forth in the responsive testimony of Mr. Jacob Pous. Mr. Pous recommends that the Commission order PSO to continue to use the depreciation rates established by this Commission in the Company's last general rate case, Cause No. PUD 201000050. The Company has provided no credible depreciation study or testimony in this docket that would support a change at this time from the previous order. My testimony supports OIEC's recommendation to retain the Commission-ordered depreciation rates from the prior cause by reversing the Company's proposed increase for the new higher rates. OIEC's depreciation adjustment (1) decreases pro forma depreciation expense to reverse the Company's proposed increase of $30,505,024 and (2) increases depreciation expense by $3,879,710 to reflect the application of existing depreciation rates to plant balances at January 31, 2014, the 6-month post test year cutoff. OIEC's net adjustment to depreciation expense is **$26,625,314**. In addition, OIEC witness Dave Parcell provides testimony regarding the Company's Cost of Capital requirements, and his testimony supports an adjustment reducing revenue requirement by **$18,072,975**.

13. **<u>Conclusion</u>**. The overall impact of the OIEC adjustments on PSO's requested revenue requirement on a total company basis is set forth below. OIEC's recommendations result in an overall $22,196,431 rate decrease.

Rate Increase Proposed by PSO	**$37,305,012**
OIEC Adjustments	**<u>($59,501,443)</u>**
Rate Decrease Proposed by OIEC	**<u>($22,196,431)</u>**

Although my recommendations do not address every potential issue affecting PSO's revenue requirement, I addressed many of 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.

<u>II. Rate Design and Cost of Service Responsive Testimony</u>

<u>1. Summary of Rate Design Cost of Service Recommendations.</u>

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

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

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

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

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

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

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

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

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

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

III. Rebuttal Testimony

The purpose of my rebuttal testimony is to comment and provide additional information on three recommendations made by the Public Utility Division (PUD) in its revenue requirement testimony in connection with the following issues, (1) short-term incentive compensation, (2) long-term incentive compensation and (3) the prepaid pension asset adjustment, and one issue addressed in PUD's rate design testimony, the 4CP Average and Excess recommendation for transmission cost allocation.

1. **Incentive Compensation Adjustments**. I disagree with the method by which PUD calculated its proposed adjustment. Although PUD's adjustment is intended to disallow 50% of PSO's short-term incentive pay consistent with prior Commission orders, PUD's adjustment removes 50% of total short-term incentive test year expense, rather than 50% of the adjusted (normalized) short-term incentive expense target levels. The Commission's prior treatment of PSO's short-term incentive compensation expense in PSO's last two litigated rate cases has disallowed 50% of the adjusted target levels, which is the proper treatment. From a ratemaking perspective, a normalization adjustment and a disallowance are two separate adjustments. A *normalization adjustment* is made to adjust an expense level to its expected ongoing level for the rate-effective period. A *disallowance adjustment*, however, is made to remove expenses that should not be recovered for ratemaking purposes. In the case of incentive compensation expense, it is necessary to normalize the expense to its expected ongoing level and then remove that portion of the ongoing level that is associated with financial-performance measures. This is the approach used by the Commission in PSO's prior cases, and I believe that it is the proper approach for ratemaking purposes. Because PUD does not make both adjustments (normalization adjustment and the disallowance) PUD's recommended incentive expense levels in rates are overstated. The Attorney General and OIEC have recommended an approach to adjusting incentive compensation expense consistent with prior Commission orders.

   With respect to long-term incentives, PUD disallows 100% of long-term incentive pay, consistent with prior Commission orders, however I disagree with PUD's calculation of that disallowance. According to PSO, the amount of long-term incentive costs from AEPSC included in pro forma operating expense was $2,907,210 and the amount of long-term incentive costs from PSO included in pro forma operating expense was $646,907, for a total of $3,554,117. PUD's total disallowance for long-term incentive costs is $2,893,003, which is $661,114 short of the total amount included in pro forma operating expense.

2. **<u>Prepaid Pension Asset Adjustments</u>.** PUD takes the position that no adjustment is necessary to PSO's proposed prepaid pension asset in rate base. PUD also asserts that inclusion of the prepaid pension asset in rate base derives the same result as the Commission's treatment in PSO's 2006 rate case, Cause No. PUD 2006-285. In that case, the Commission (1) removed the pension asset from rate base, (2) provided a cost of debt return on the pension asset balance, but then (3) made a capital structure debt adjustment that had the effect of wiping out the first two adjustments. That position, however, fails to take into account the fact that the capital structure adjustment issue was litigated in PSO's next rate case, Cause No. PUD 2008-144, and the Commission chose **<u>not</u>** to make the capital structure adjustment again. PSO appealed that decision to the Oklahoma Supreme Court where the court upheld the Commission's decision.

In Oklahoma, the Commission's treatment of Prepaid Pension Assets is fairly well established. The issue has been addressed in four separate proceedings and in each proceeding the Commission has authorized the removal of the prepaid asset from rate base and a cost of money return on the balance. The cost of money return in each case was set at the utility's cost of long-term debt. In one case, PSO's 2006 rate case, the Commission made a capital structure adjustment for debt allegedly assigned to the asset, but chose not to follow that approach in the Company's next rate case.

I am recommending that the prepaid asset balance be removed from rate base and provided a cost of money return instead. In this case, though, I am recommending that the cost of money return be set at the "expected return" on pension fund assets, which is higher than a cost of debt return but lower than a full rate base return. This treatment has the added benefit of setting the return level for the utility at the same benefit level ratepayers receive from the excess contributions. In other words, PSO will receive the same benefit ratepayers receive from the excess contributions. The impact of these adjustments is calculated at Exhibit MG-Rebuttal 1 and set forth in the table below.

Table 2: Adjustment Impacts

Description	Rate Base Amount	ROR w/Tax	Revenue Requirement Impact
PUD's Filed Rate Decrease			**($7,294,274)**
Short-term Incentives			($3,597,456)
Long-term Incentives			($661,114)
Prepaid Pension Rate Base Adj.	$67,741,716	11.206%	($7,591,809)
Prepaid Pension Return Adj.			$4,403,602
Total Additional Decrease			**($7,447,777)**
PUD's Adjusted Rate Decrease			($14,742,051)

3. **<u>Depreciation Adjustment</u>**. In his rate design testimony, the Attorney General's witness, Mr. Farrar, states that he cannot accept PSO's recommended increases to depreciation rates. Mr. Farrar's position is consistent with the positions taken by both

PUD and OIEC. However, Mr. Farrar's testimony does not quantify the impact of this recommendation on the revenue requirement recommendation which was previously made in testimony filed on April 23, 2014. I have quantified the impact of the adjustment, which by my calculation, decreases the Attorney General's revenue requirement by $10,279,651. This calculation is not intended to state the Attorney General's revenue requirement recommendation, but is intended to reflect the rate impact excluding PSO's proposed depreciation rate increase. Based on the testimony of the parties, PUD, OIEC and the Attorney General are ALL recommending substantial rate decreases, which certainly underscores the importance that a rate decrease will result from these proceedings. That being the case, it is also important for ratepayers and the economy of Oklahoma that a decrease be implemented as soon as possible.

4. **4CP Average and Excess Allocation of Transmission Costs**. On pages 19 and 20 of his direct testimony, PUD witness Mr. Saenz disagrees with PSO's recommendation to change the allocation method for transmission plant from a 4CP to a 12CP method and recommends instead using a 4CP A&E method. OIEC also disagreed with PSO's recommendation to change from a 4CP to a 12CP allocation for transmission plant and recommended not change the current utilized transmission allocation which is a straight 4CP method.

While I believe a straight CP method is more-commonly used to allocate transmission plant, a 4CP/A&E method would also be acceptable. The 4CP/A&E method would result in allocations to the various customer classes similar to the straight 4CP method. Both methods are consistent with the rate structure proposed by PSO both historically and in the current case. Mr. Saenz is correct in stating in his testimony that the PSO requested 12CP allocation for transmission is inconsistent with pricing signals of PSO's current and proposed rate structures. Mr. Saenz is also correct when he points out that PSO's response to PUDLS-03-10 shows that the transmission system was planned to avoid thermal and voltage violations under peak loading conditions. Mr. Saenz's testimony correctly recognizes that the transmission allocation method should reflect the fact that PSO's system is a summer peaking system.

Mr. Saenz used the PSO-supported four summer month demands in developing his cost of service. In my direct rate design testimony beginning on page 10, I pointed out that there are severe problems with PSO's proposed demand units for the summer months used to develop [*sic*] cost allocations to the LPL1 and LPL2 classes. My recommendation remains the same, that the average demands for the four summer peak months be reduced for these classes from that supported by PSO to more realistic levels.

In my rate design testimony I recommended reducing the LPL1 average summer demand units used to develop the 4CP allocator from PSO's proposed 82,204 kW to a more normal 73,318 kW. I also recommended reducing the LPL2 average summer demand units from PSO's proposed 357,221 kW to a more normal 347,367 kW.

I recommend that Staff revise its cost of service based upon these changes. Making these changes would result in a more reasonable cost assignment of transmission assets and expenses to the industrial classes. The resulting impact on the other classes from this change would be minimal, but the impact to the LPL1 and LPL2 classes would be significant. This change also affects the allocation of production costs to the classes. The kW units I recommend should also be used to revise the production costs allocations. Again, the resulting impact from this change would be minimal to the other classes but significant to the LPL1 and LPL2 classes.

IV. Sur-rebuttal Testimony Outline

Item	Witness	Rebuttal Testimony Page Reference	Summary of Issue
1	Carlin	Pg. 5, ln 11 — Pg. 11, ln 9	Annual Incentive Compensation in Operating Expense
2	Carlin	Pg. 13, ln 12 — Pg. 17, ln 5	OIEC's recommendation to exclude 50% of annual incentive compensation from cost of service
3	Carlin	Pg. 17, ln 8 — Pg. 19, ln 13	Long Term Incentive Compensation recommendations
4	Carlin	Pg. 21, ln 3 — Pg. 23, ln 21	Whether recovery of Long Term Incentive Compensation program is reasonable or necessary
5	Carlin	Pg. 24, ln 2 — Pg. 25, ln 5	Adjustment to remove incentive compensation from rate base
6	Carlin	Pg. 26, ln 7 — Pg. 28, ln 16	Supplemental Employee Retirement Plan (SERP) adjustment
7	Sartin	Pg. 9, ln 9-20	Costs and benefits of AMI rider
8	Sartin	Pg. 10, ln 13 — Pg. 13, ln 19	SPPTC Tariff Concerns
9	Sartin	Pg. 20, ln 17-20	Vegetation Management Rider
10	Sartin	Pg. 22, ln 7-23	OIEC participation in fuel factor setting process
12	Sartin	Pg. 23, ln 15 — Pg. 25, ln 21	OIEC recommendations on other rider issues
13	Murray	Pg. 19, ln 11 — Pg. 23, ln 7	Analysis of risk factors associated with PSO's rate riders
14	Hakimi	Pg. 7, ln 19 — Pg. 20, ln 2	OSS Margin Sharing

Item	Witness	Rebuttal Testimony Page Reference	Summary of Issue
15	Hakimi	Pg. 21, ln 5 — Pg. 26, ln 7	West Operating Agreement Modifications
16	Hamlett	Pg. 12, ln 8 — Pg. 17, ln 17	Prepaid Pension Asset
17	Hamlett	Pg. 17, ln 18 — Pg. 18, ln 16	Fuel and Materials and Supplies inventories
18	Hamlett	Pg. 19, ln 11 — Pg. 17, ln 17	Accumulated Deferred Income Taxes
19	Hamlett	Pg. 20, ln 11 — Pg. 21, ln 22	Recommendations on Capitalized Incentives
20	Hamlett	Pg. 22, ln 7 — Pg. 24, ln 4	July 2013 Storm Regulatory Asset
21	Hamlett	Pg. 25, ln 13 — Pg. 29, ln 20	Payroll and Payroll related taxes
22	Hamlett	Pg. 47, ln 12 — Pg. 49, ln 17	Recovery of rate case expense
23	Hamlett	Pg. 49, ln 19 — Pg. 50, ln 21	Incentive compensation expense
24	Hamlett	Pg. 52, ln 5-12	Return on Pension Asset
25	Hamlett	Pg. 53, ln 11 — Pg. 54, ln 8	AMI O&M Costs in Base Rates
26	Ross	Pg. 5, ln 11 — Pg. 12, ln 8	SPPTC Tariff and PSO's participation in SPP stakeholder process
27	Ross	Pg. 14, ln 6 — Pg. 21, ln 2	Comments regarding monitoring and reasonableness of PSO'S Project costs
28	Griffin	Pg. 3, ln 13 — Pg. 5, ln 4	OIEC's proposed adjustments to AEPSC's Annualized Labor costs
29	Baker	Pg. 4, ln 9 — Pg. 13, ln 11	Costs, risks and benefits associated with the System Reliability Rider (SRR) formerly, the RVU Rider
30	Jackson	Pg. 16, ln 3 — Pg. 18, ln 4	Industrial Rate Design (LPL 1, 2, 3); Claim that OIEC proposes higher demand charges and lower kWh charges

Item	Witness	Rebuttal Testimony Page Reference	Summary of Issue
32	Aaron	Pg. 5, ln 9 — Pg. 6, ln 13	Industrial Rate Design (LPL 1, 2, 3); 12-CP Transmission allocation and "Synchronize" allocation and rate charges
33	Aaron	Pg. 6, ln 14 — Pg. 7, ln 9	Industrial Rate Design (LPL 1, 2, 3); 12-CP Transmission allocation and "the change to a 12-CP transmission allocation alters PSO's price signal to customers."
34	Aaron	Pg. 7, ln 10 — Pg. 8, ln 3	Industrial Rate Design (LPL 1, 2, 3); Proper cost allocation and resulting price signals
35	Aaron	Pg. 11, ln 13 — Pg. 13, ln 10	SPPTC Tariff Concerns
36	Aaron	Pg. 13, ln 20 — Pg. 15, ln 2	Real Time Pricing (RTP) Revenues regarding understated revenues from the termination of RTP program
37	Aaron	Pg. 16, ln 1 — Pg. 18, ln 15	Industrial Class Cost of Service Demands (LPL 1, 2); Matching of cost of service demands (kW) to revenues
38	Aaron	Pg. 15, ln 12-23	Standby Revenues used to reflect charges as approved in PUD 2013-201; Additional revenues from recently approved standby tariffs

<u>Summary of the Responsive Testimony and Surrebuttal Testimony Issues of David C. Parcell</u>

David Parcell filed Direct Testimony on behalf of OIEC, Walmart and Sam's on April 23, 2014, and filed his Surrebuttal Testimony Issues on June 17, 2014. Mr. Parcell's Direct Testimony and Exhibits are concerned with developing the cost of capital for Public Service Company of Oklahoma ("PSO"). His cost of capital recommendations can be summarized as follows:

Capital Item	Percent	Cost	Return
Long-Term Debt	51.31%	5.51%	2.83%
Common Equity	48.69%	9.5-9.5%	4.38-4.63%
Total Cost of Capital	100.00%		7.21-7.45%
			7.33% Mid-Point

Mr. Parcell accepts PSO's proposed capital structure and cost of long-term debt. He disagrees with PSO's proposed 10.50% cost of common equity.

Mr. Parcell's cost of common equity employs two sets of proxy electric utilities, one of which is developed by Mr. Parcell and the other of which is the proxy group used by PSO's cost of capital witness Dr. Murry, and the application of three recognized cost of equity methodologies. His results are as follows:

Methodology	Range	Mid-Point
Discounted Cash Flow	8.6-9.4%	9.00%
Capital Asset Pricing Model	7.5-7.6%	7.55%
Comparable Earnings	9.0-10.0%	9.50%

In reaching his conclusions and recommendation, Mr. Parcell focuses on the mid-point results of his DCF and CE analyses. This results in a cost of equity range of 9.0% to 9.5%, with a mid-point of 9.25%.

Mr. Parcell recommends a cost of equity of 9.5% and an overall cost of capital of 7.33% for PSO.

Mr. Parcell's Direct Testimony also demonstrates that the 10.50% cost of equity recommended by PSO witness Dr. Murry is excessive and should not be adopted by the Commission.

In his Surrebuttal Testimony Issues filing made on June 17, 2014, Mr. Parcell identifies the Issues that he will address in his Surrebuttal Testimony to be provided at the merits hearing scheduled in this proceeding. Mr. Parcell identifies, by page and line number, the matters that he will address in the Rebuttal Testimony of PSO witness Donald A. Murry.

<u>Summary of the Responsive Testimony and Surrebuttal Testimony Issues of Jacob Pous</u>

Jacob Pous filed Direct Testimony on behalf of OIEC, Walmart and Sam's on April 23, 2014 and filed his Surrebuttal Testimony Issues on June 17, 2014. Mr. Pous is a principal in the firm of Diversified Utility Consultants, Inc. (DUCI), a consulting firm located in Austin, Texas. Mr. Pous is a registered professional engineer who has participated in over 400 utility rate proceedings in the United States and Canada. He has testified on behalf of the Staff of six different state regulatory commissions and one Canadian regulatory commission.

In this proceeding, PSO retained a new depreciation witness who proposed rates that result in an annual level of depreciation expense of $112,997,178 based on plant as of December 31, 2012. Mr. Pous received and analyzed PSO's request and underlying support. Based on his analysis, he makes two recommendations. Mr. Pous' primary recommendation is to retain the existing depreciation rate. Mr. Pous' primary recommendation results in a $26,625,314 reduction in existing depreciation expense based on plant as of January 31, 2014. In the event the Commission elects not to retain the existing depreciation rates and decides to make decisions based on the new depreciation study, then Mr. Pous makes alternative recommendations [*sic*] for various accounts, excluding distribution plant. The alternative recommendations result in an annual level of depreciation expense of $84,978,656 based on plant as of December 31, 2012. The following is a brief synopsis of each recommended adjustment.

- **Production Plant Net Salvage** – The Company proposes various negative net salvage values for its steam and other production generating units. These values are based on demolition cost studies recently updated by Sargent & Lundy, LLC ("S&L") which were then inflated far into the future by Gannett Fleming, Inc. (GF). The impact of the Company's process is set forth in the following table.

Demolition Cost Levels

	S&L Amount	PSO Inflated
All Units	$59 million	$141 million
Ratio to S&L	1.00	2.39

In addition, GF also estimated net salvage amounts for interim retirements and added those amounts in order to arrive at a negative 15.1% overall net salvage result for total production plant.

Mr. Pous recommends that a negative net salvage level of 2.3% is a more appropriate value for production plant. This recommendation is more in line with the negative 2.6% level of net salvage recently proposed by one of PSO's sister-operating companies in Texas. Reliance on an overall 2.3% negative net salvage results in an $8,053,514 reduction to the proposed depreciation expense based on production plant as of December 31, 2012.

One major and fatal flaw to PSO's request, and there are others, is that it is inconsistent. The majority of the proposed S&L costs are attributable to the restoration of the various power plant sites, not the removal of the equipment that rests upon the sites. Inconsistently, the Company notes that there are limited good generating station sites in the country, but fails to recognize any value for the valuable restored sites. If the value of the restored site is not recognized, then projected costs to restore and improve the site cannot be assigned to current customers. Future customers or new owners will receive the benefit of the restored or improved sites through the sale of the sites or through reuse of the site for future generation. In either instance, the matching principle requires consistency between costs and benefits, which is missing from the Company's proposal.

Finally, GF's action of escalating the proposed cost of decommissioning at an annual rate of 2.5% for many years into the future is inappropriate and illogical. It is patently unreasonable and inequitable to request that current customers pay with their current dollars for future escalated costs. This request by PSO creates a tremendous level of intergenerational inequity.

- **Interim Retirements** – The Company proposes to alter the method it uses when estimating interim retirements in calculating depreciation rates. For the first time, the Company proposes to employ a truncated Iowa Survivor curve to predict the future levels of interim retirements that might occur prior to final retirement of a generating plant. The new process proposed by the Company relies on an actuarial approach. The Company fails to recognize that actuarial analysis requires a greater degree of homogeneality of assets being analyzed if reliable results are to be obtained. Production plant investments vary too greatly within an account to properly be analyzed through an actuarial approach. Moreover, GF's new approach for estimating future interim retirements results in a dramatically higher level of interim retirements from what the Company proposed within the last 3 years.

  GF's unreasonable interpretation of the results of a new interim retirement approach for this Company resulted in estimated future interim retirements at a level more than doubling that previously estimated by the Company. GF's new approach results in $350 million of estimated interim retirements, while in the Company's last proceeding, only $160 million of interim retirements were estimated. On its face, a more than doubling of interim retirements within a three-year time span demands a significant level of justification. Such justification has not and cannot be provided by the Company.

  Given the fact that (1) a higher level of interim retirements results in a higher level of depreciation expense, (2) the Company now estimates more than 100% increase in the level of interim retirements in just a three-year period, and (3) the level of support provided by the Company for its new position is inadequate, no change in methods should be adopted.

  The impact of retaining the existing method of estimating interim retirements results in a $1,587,232 reduction in annual depreciation expense for plant as of December 31, 2012.

- **Interim Net Salvage** – The Company's proposal for interim net salvage reflects a -20% net salvage for steam production plant and a -5% for other production plant. The Company's basis for its proposals appears to be an averaging of historical data during the last 10-year period.

  The historical data is unstable and contains unusual activity such as significant environmental modifications to the Company's generating stations. Also, the 10-year period relied upon by the Company deviates significantly from the 28-year historical database it relied upon for mass property net salvage analyses. The inconsistent selection of historical databases further calls into question the lack of proper evaluation and explanation of information. The Company fails to demonstrate that the limited historical data is representative [*sic*], and that it is a valid basis for predicting future activity. For example, the Company's historical activity for Account 314 includes a reported -189% net salvage. This one occurrence represented 40% of the entire removal cost experienced during the entire 10-year period analyzed. For this account, the Company has not shown in any manner the validity of relying on such a significant and unusual outlier.

Another inconsistency reflected in GF's analyses is its unexplained but varying use of informed judgment. For mass property accounts, GF relied on undefined "informed judgment" to propose significant reductions in the level of negative net salvage compared to that reflected in the historical database. Yet without support or justification, GF fails to perform comparable modifications for production plant.

Based on a review of the historical database, taking into account the unstable historical activity and eliminating outliers, a less negative level of net salvage is warranted. A more appropriate interim net salvage level for steam production is a -10% with a corresponding zero (0) level of net salvage for other production plant.

The impact of the less negative levels of interim net salvage results in a $1,275,753 reduction in annual depreciation expense based on plant as of December 31, 2012.

- **<u>Mass Property Life Analysis</u>** – GF employed an actuarial approach to establish [*sic*] a life-curve combination it believed is indicative of the retirement pattern expected for its investment. The interpretation of actuarial results requires judgment, but the final result must still be substantiated based on factors that influence the judgmental decision in a meaningful or significant manner. GF failed to provide meaningful information associated with its claimed informed judgment process when establishing life characteristics for many mass property accounts. In other words, GF proposed results without often justifying how it arrived at its proposals, other than reliance on the phrase "informed judgment."

  In addition to the actuarial approach used for most accounts, GF also relied on amortization periods for many general plant accounts. GF chose not to perform any life analysis when establishing general plant amortization periods. Again, GF attempted to rely on claims of informed judgment without any further definition of why the unidentified informed judgment resulted in the most appropriate amortization period. When actual data is investigated, it is clear that much of the investment in the accounts is still in service subsequent to the assumed amortization periods. In other words, the amortization periods proposed by GF, based on claimed informed judgment, are artificially short when compared to actual experience.

  A clear example as to why claims of unsubstantiated informed judgment cannot be accepted as adequate basis for proposed life characteristics of mass property can be illustrated through what transpired for Transmission Account 350.1 – Land Rights. GF provided no basis for its proposal other than the general claim of reliance on the informed judgment. However, when the investment in the account is analyzed, one finds that the vast majority of the investment corresponds to perpetual land rights. Land rights must be in place for a minimum of one complete life cycle of the investment that resides upon it. However, in reality, land rights are in place for periods longer than one life cycle as replacement investment that resides on it also must use the same initial land right and must further complete a complete life cycle for the replacement activity. GF's proposed informed judgment resulted in a 75-year average service life. It must be noted that GF proposed a 65R2.5 life-curve combination for Transmission Account 356 – Overhead

Conductors & Devices, which results in a maximum life or a complete life cycle in excess of 120 years. Thus, GF's proposed 75-year average service life falls woefully short of the timeframe necessary to complete an initial life cycle for the investment residing upon the land right.

Even in those instances where actuarial analysis was performed, GF's interpretation of the results produce artificially short average service lives. GF's unexplained and unsubstantiated claim of informed judgment can be demonstrated to produce inaccurate results in many instances. For example, for Account 355 GF proposed to shorten the existing average service life by two years from the last case. However, as demonstrated through analysis of actuarial results, GF's proposal is a poorer fit than is the retention of the existing 54-year average service life. In other words, GF's claim of informed judgment as its basis for its proposal is not substantiated in any manner, and in fact is refuted by the actuarial results it developed.

Given (1) GF's failure to support its proposals, (2) recognition of specific actuarial analysis results that support longer average service lives compared to GF's interpretation of results, and (3) the fact that the Company's actual plant in service for general plant subject to amortization often exceeds the assumed amortization periods, longer average service lives are warranted for a minimum of seven different transmission and general plant accounts (noting that distribution accounts were not analyzed). The impact of adjusting the seven different transmission and/or general plant accounts is summarized in the table below and results in a $3,853,150 reduction in annual depreciation expense based on plant as of December 31, 2012.

Summary of OIEC's Recommended Mass Property Life Adjustments

Account	PSO Proposed	OIEC Proposed	OIEC Adjustment	Impact
350.1 – Transmission Land Rights	75R4	100R4	25	$107,317
353 – Transmission Station Equipment	60R1.5	63S0	3	$197,428
355 – Transmission Poles & Fixtures	52S0.5	54S0.5	2	$596,176
356 – Transmission OH Conductors & Devices	65R2.5	69R2.5	2	$413,181
391.1 – Office Furniture & Equipment	20SQ	25SQ	5	$1,790,479
395 – Laboratory Equipment	20SQ	25SQ	5	$263,192
397 – Communication Equipment	15SQ	20SQ	5	$485,377
Total				**$3,853,150**

- **Mass Property Net Salvage** – GF performed a historical net salvage analysis for mass property accounts (i.e., transmission, distribution and general plant). A review of the Company's testimony, exhibits, workpapers and responses to data requests demonstrates that GF often deviates from the results of its averaging of historical data. GF's proposals often rely heavily on the process of employing informed judgment, yet it takes the unrealistic position that the judgment process it employed cannot be detailed by account.

GF's analyses fail to evaluate the available information properly. GF fails to recognize the differences in the mix of assets retired versus those in service. GF also fails to address the disproportionate impact that emergency retirements such as ice storms and tornadoes had on the historical data.

Another significant, but indicative, problem with GF's net salvage analysis is its proposal for a zero (0) percent net salvage for Account 392 – General Plant Transportation Equipment. The proposal is illogical on its face. Yet in this instance, GF elected to rely on the historical average of a truncated database. A review of the actual resale value for a truck in the Tulsa area clearly refutes GF's illogical proposal. Used vehicles do have residual value.

Correction of the net salvage value proposed for four mass property accounts results in $1,244,119 reduction to depreciation expense based on plant as of December 31, 2012. A summary of the recommended changes follows.

Summary of OIEC's Recommended Mass Property Net Salvage Adjustments

Account	PSO Existing	PSO Proposed	OIEC Recommended	Impact
353 – Transmission Station Equipment	(4%)	(10%)	(5%)	$295,398
356 – Transmission OH Conductors & Devices	(38%)	(60%)	(45%)	$512,828
390 – Structures & Improvements	35%	(5%)	25%	$296,054
392 – Transportation Equipment	0%	0%	17%	$189,839
Total				**$1,294,119**

In his Surrebuttal Testimony Issues Filing made on June 17, 2014, Mr. Pous identifies the issues that he will address in his surrebuttal testimony to be provided at the Merits Hearing scheduled in this proceeding. Mr. Pous identifies, by page and line number, the matters that he will address in the Rebuttal Testimony of PSO witnesses Bertheau and Spanos.

Summary of the Supplemental Testimony in Support of Joint Stipulation and Settlement Agreement of 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 for PSO in support of the Joint Stipulation and Settlement Agreement (Stipulation and Agreement or Stipulation). According to Mr. Sartin, PSO requests approval because the Stipulation and Agreement provides for a fair, just, and reasonable resolution of all issues in this proceeding, and because it is in the public interest. According to Mr. Sartin, the Stipulation was forged by the significant compromise of the disparate positions among the Stipulating Parties. It is in the public interest because, among other things, it provides:

1. no change to the existing overall rates to PSO's customers except for an Advanced Metering Infrastructure (AMI) Tariff, yet allows a reasonable level of revenues for PSO;

2. customers a proven AMI technology to enhance their ability to understand and manage their electric costs, while enabling many customer beneficial service quality enhancements;

3. an AMI Tariff that provides recovery of AMI costs as they are incurred over a three-year deployment period, and a time certain tariff cessation when AMI is fully deployed and such costs are included in base rates following a used and useful determination by the Commission in a subsequent base rate case; and

4. a reasonable allocation of costs and revenues among customer classes that provides no change in the existing allocation of costs among the customer classes, and the allocation of AMI costs based on the direct use and benefits of the AMI technology by each of the classes.

The Stipulation and Agreement confirms that PSO's current overall rates are reasonable and should remain in effect. It confirms that AMI provides substantial value to PSO customers, while allocating costs to benefiting customers, and providing cost recovery through the AMI Tariff contemporaneous with the benefits provided in a fashion very similar to that afforded to Oklahoma Gas and Electric Company in Cause No. 201000029, Order No. 576595.

According to Mr. Sartin, PSO filed the application to comply with OCC Order No. 591185, issued in Cause No. PUD 201100106, which required PSO to file a base rate case no later than January 18, 2014.

Mr. Sartin testified that the Procedural Schedule in this cause established a settlement conference on May 15. The parties first met as a group on this date and then multiple times thereafter. All parties were provided notice of each of the group negotiations that occurred. In addition, PSO had individual discussions with some of the parties to better understand their views and try to provide as comprehensive of a settlement for as many parties as possible. On June 17, an executed agreement was filed.

The Stipulating Parties represent all customer classes and a diverse group of interests with significant and substantially opposing and conflicting positions.

Mr. Sartin testified that much of PSO's original request for a base rate increase was caused by the need to increase deprecation rates to more timely recover its investment in electric system assets made for the benefit of customers. Mr. Sartin testified that while it is unfortunate that depreciation rates are not changed as a result of the Stipulation, as low depreciation rates push cost recovery to future generations of customers, there will be opportunities in future base rate cases to appropriately adjust depreciation rates.

In essence, without the change requested in depreciation rates and other adjustments, the Stipulation indicates PSO's existing revenues are reasonable. This is in part due to PSO's and AEP's continued focus on managing expenses and investments since the last time PSO's base rates were reviewed in 2010.

Mr. Sartin described the Stipulation as providing the following:

1. PSO has complied with the provisions of Order No. 591185 in Cause No. PUD 201100106 in filing this base rate case, and in determining that the Southwest Power Pool Transmission Cost Tariff should be extended until further order of the Commission. It also modifies that tariff so demand-metered customers taking service from PSO's SL1, SL2, and SL3 tariffs are charged on a demand basis.

2. PSO's current retail operating base revenues are $537,719,075, and PSO has provided tariffs designed to produce these revenues;

3. PSO's rate base of $1,908,675,876, which reflects a six-month post test year level, is used and useful;

4. The effective date of new rates is the first billing cycle of November 2014, which will include an overall impact on total customers' rates of 2.05 percent, and an increase for the total average residential class of $3.11 per month, which is a 3.82 percent change. The changes to other customers classes are provided in Attachment D of the Stipulation;

5. Although having no impact on overall customer rates, certain fuel-related provisions:

    a. remove the 3.4 cents per kilowatt-hour of fuel costs included in base revenues and include them in the Fuel Adjustment Clause (FAC);

    b. move $4.8 million of fuel costs currently in base revenues to the FAC;

    c. provide no change in the existing off-system sales sharing between customers and PSO; and

    d. require costs currently recovered under Base Load Purchased Power Rider (BLPP) and Purchased Power Capacity Rider (PPC) be moved for recovery under the FAC, and the BLPP and PPC riders be eliminated.

6. Creates the AMI Tariff, and provides the basis for its annual determination beginning with the first billing cycle of November 2014, which recovers the first 14 months of AMI costs initially, followed by annual redeterminations thereafter. The AMI provisions also include:

    a. guaranteed savings of $11 million for labor, vehicles, and overheads during the first four years;

b. AMI investment at January 31, 2014, of $16,020,263, is used and useful. Future levels of AMI investment may be found used and useful by the Commission in future regulatory proceedings;

c. establishment of a regulatory asset for non-AMI meters as they are replaced by AMI meters, with cost recovery of non-AMI meters using a 9.58 percent depreciation rate;

d. the use of over-/under- accounting for regulatory assets and liabilities associated with the difference between actual AMI revenue requirements and actual AMI revenues collected under the AMI Tariff;

e. the return on AMI assets at the authorized return; and

f. PSO is to provide free Home Energy Reports for any requesting customer with an AMI meter.

7. An authorized return on rate base of 7.63 percent;

8. For the purposes of calculations of Allowance for Funds Used During Construction and factoring, and for the riders with an equity component, the return on common stock equity is 9.85 percent;

9. PSO's existing depreciation rates do not change, except for those associated with AMI investments and existing meters;

10. PSO rate case expenses and PUD expert costs paid by PSO are amortized to expense over a two-year period;

11. PSO operation and maintenance storm expenses from prior storms are recovered over a four-year [sic] period, and included in rate base;

12. PSO's interim Standby and Supplemental Service Tariff is made final; and

13. PSO's Residential Service Base Service Charge is increased to $20 per month, offset in total by decreases to residential per kilowatt-hour charges.

According to Mr. Sartin, from an overall perspective, the significant benefits of the Stipulation are that it:

1. keeps in place the current level of overall rates;

2. provides an AMI Tariff which permits expansion of this technology and the attendant substantial benefits to all PSO customers;

3. keeps in place current depreciation rates, except for changes to AMI investment and existing meter rates;

4. results in a reasonable allocation of costs and revenues among customer classes;

5. resolves all issues without significantly adding to rate case expense;

6. includes a four-year amortization of $18 million operation and maintenance storm expenses without an increase in rates; and

7. adds certainty to uncertain litigated outcomes for each of the Stipulating Parties.

Mr. Sartin testified that PSO supports the Settlement Agreement and requests the Commission to approve it.

Summary of the Direct and Rebuttal Testimonies of 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 PSO filed this application at this time to comply with OCC Order No. 591185, issued in Cause No. PUD 201100106. In that Cause, PSO requested a Commission order approving a tariff (the Southwest Power Pool Transmission Cost (SPPTC) tariff), to collect certain costs that PSO incurs by virtue of its membership in the Southwest Power Pool, Inc. (SPP). Paragraph 7 of the OCC's Findings of Fact and Conclusions of Law provided:

The Commission further finds that no later than twenty-six months following the (sic) date of this order, PSO shall file a general base rate case for the purpose of determining whether the SPPTC Tariff should be amended, extended or terminated and also for the purpose of conducting a review of the testimony submitted by PSO regarding the SPPTC Tariff described in paragraph 5(vii) above.

Pursuant to the filing requirements above, PSO was required to file this case by January 18, 2014.

Mr. Sartin explained that PSO was requesting a total increase in customers' rates of $45 million. This included a base rate increase of $38 million due to a revenue deficiency based on a test year ended July 31, 2013, adjusted for known and measurable changes to test year levels. In addition, PSO was requesting the creation of a new tariff, and associated regulatory asset, to recover the costs of advanced metering infrastructure (AMI). The total requested increase would change PSO customers' rates by 4%. PSO was also requesting an expansion of the SPPTC tariff, the cost of which is currently included in the base rate revenue deficiency discussed above.

Mr. Sartin testified the primary reason for the requested increase in rates is the increase in PSO's cost to provide electric service since the last time PSO adjusted its rates. The primary changes are as follows (dollars in millions):

Depreciation	$29
Operation and maintenance	13
Income and other taxes	15
Return and other	9
Revenues	(28)
	$38

According to Mr. Sartin, the depreciation 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 transmission service expense. If PSO's proposed changes to the transmission tariff are approved by the OCC, the amount of base rates is reduced, but the customer rate increase would not change since the costs would then be recovered via a tariff.

Income and other taxes reflect higher property taxes from increased taxable electric assets, and income taxes have grown because of the tax effect of the return on a growing rate base. Return and other increased predominantly from the higher costs of financing the increased balances of electric utility assets, including PSO's request to modestly increase its return on equity from 10.15% to 10.5%.

Mr. Sartin further testified that revenues have increased since the last time rates were set, which reduces the overall revenue requirement. The increased revenues are mostly from higher numbers of customers resulting in increased total kilowatt-hour sales.

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

According to Mr. Sartin, PSO tracks its customer satisfaction through the J.D. Power & Associates residential survey. In the last survey (July 2013), PSO's customer satisfaction increased from a score of 626 to 640, and our results have continued to improve from a score of 592 in 2009. It is PSO's goal to continue to increase customer satisfaction as measured by this survey.

Commission complaints specific to customer service quality continue to be at low levels for PSO. For the past five years, PSO has averaged less than 80 complaints per year and the number is trending downward. With over 535,000 customers, this low level of customer complaints is another indication of our focus on quality customer service. Mr. Sartin testified that Paragraph 7 of the Findings of Fact and Conclusions of Law of Order

No. 591185 required the filing of this case by January 18, 2014, and required this filing to contain certain information about the costs recovered through the SPPTC. According to Mr. Sartin, PSO has complied in this filing with that provision.

Further, Paragraph 6 of the Findings of Fact in Order No. 591185 required that in this rate case that PSO submit testimony:

1) identifying each of the third-party upgrades and facilities that were constructed and included in the Third-Party Owned Transmission Costs recovered from Oklahoma retail customers and identifying the benefits (economic or otherwise) that such upgrades and facilities provide to the regional grid and PSO's Oklahoma retail customers;

2) demonstrating that the amounts recovered under its SPPTC Tariff were reasonable, eligible for recovery, properly calculated, and appropriately allocated to PSO's various customer rate classes;

3) demonstrating that the facilities were approved by the SPP, and the costs of such upgrades are included in FERC-approved rates and allocated to PSO under a FERC-approved SPP cost allocation methodology; and

4) identifying the rate impact on PSO's various customer classes of the amounts recovered by PSO pursuant to the SPPTC Tariff and also identifying the rate impact of the amounts projected to be recovered by PSO pursuant to its SPPTC Tariff.

The above information was contained in the Direct Testimonies of PSO witnesses Aaron and Nickell.

Mr. Sartin further testified that PSO was requesting two changes to the SPPTC tariff. First, PSO requests that the SPPTC tariff be expanded to include costs paid by PSO to SPP for transmission service from the facilities of PSO's affiliated transmission utilities under the SPP Open Access Transmission Tariff (OATT) Schedule 11 Federal Energy Regulatory Commission (FERC)-approved tariffs. Second, PSO requests that the SPPTC tariff be expanded to recover SPP OATT FERC-approved Schedule 9 Network Integration Transmission Service (NITS) costs from transmission owners other than PSO because of dramatic cost increases expected for these transmission services over the next several years. PSO is a NITS customer under the SPP OATT, and this service is required to reliably serve its retail customers.

Mr. Sartin stated the costs to be recovered under the AMI Tariff would be the revenue requirements expected to be incurred on an annual basis associated with: (1) a rate of return (including federal and state income taxes) on rate base on the AMI assets; (2) operation and maintenance expenses (net of savings); (3) depreciation; (4) property taxes; and (5) severance amortization.

Mr. Sartin stated that Oklahoma Gas and Electric Company (OG&E) was permitted tariff cost recovery of AMI costs in Cause No. PUD 201000029, Order No. 576595. PSO's request was very similar to the relief provided to OG&E in that Cause.

Mr. Sartin's rebuttal testimony stated that PSO has fully supported its need for a $42 million base rate increase, and $7 million of first-year revenues for full AMI deployment.

PSO has also supported its need for an expansion of the SPPTC Tariff to permit timely recovery of the substantial increases in SPP transmission cost expected over the next several years. A primary opposition to this proposal from other parties appears not to be founded in the specific needs for the SPPTC Tariff expansion, but rather in a fundamental opposition to riders in general. Some parties make claims as to the perceived violation of their inherent regulatory principles as reasons to oppose riders. According to Mr. Sartin, they appear to clamor for regulatory policies and practices going back to the inception of utility regulation when riders were not as predominant, with a fervent desire to return to those days; to the extent, those days ever really existed.

The use of riders by regulatory commissions has been a common tool by regulators for at least the past 35 years. Unlike described in some of the other parties' testimonies, riders are not a poor regulatory practice. They are a common sense approach to permitting utilities to recover certain costs between rate cases for the benefit of companies and customers, and for the efficient administration of the rate setting process by regulators.

Mr. Sartin further testified that PSO's depreciation rates should be reviewed in this Cause. It is not a reasoned position to assert that just because depreciation will be an issue in a future rate case that it should not be addressed currently. The longer PSO's depreciation rates continue to under-collect costs, the more costs are pushed to future generations of customers.

While PSO is sensitive to the societal needs of low-income customers, PSO's expertise is meeting the electric service needs of our customers; its expertise does not extend to low income societal issues. Low-income tariffs should not be required.

Summary of the Direct Testimony of Derek S. Lewellen

Mr. Derek S. Lewellen, employed as the Manager of gridSMART® and Meter Revenue Operations for Public Service Company of Oklahoma (PSO or Company) testified on behalf of the Company. Mr. Lewellen explained that his testimony gives an update on PSO's gridSMART® projects, discusses the Company's proposal to deploy advanced metering infrastructure (AMI) throughout its service territory and associated consumer programs, and provides information regarding the Company's future plans for gridSMART® deployment.

Mr. Lewellen testified that gridSMART® is American Electric Power Company, Inc.'s (AEP) name for its smart grid program. PSO's gridSMART® program is an initiative that started in 2010 and includes advanced metering (metering capable of two-way communication) at customers' residential and business locations, and advanced grid management technology equipment on PSO's distribution system. The main components of PSO's smart grid program include AMI, distribution automation (DA), volt/var optimization (VVO), in-home devices, and a customer web portal.

AMI refers to systems that measure, collect, and analyze energy usage from meters through a communications network. This infrastructure includes hardware, such as meters that enable two-way communications (AMI meter), the communications network, customer information systems, and meter data management systems.

The DA component includes automated circuit reconfiguration on distribution circuits and substations, and involves the installation of automated reclosures to reduce the number of customers impacted by an outage.

The VVO component includes the coordinated control of capacitor banks, voltage regulators, and transformer load tap changers on distribution circuits and substations to optimize voltage and power factors.

The in-home device component assists customers in managing electric usage in conjunction with tariffs, such as time of day (TOD) and direct load control (DLC) tariffs.

PSO's customer web portal includes: single account sign-on via existing customer account log-in, bill-to-date and forecasted bill; daily, weekly, and monthly use; existing rate plan information and rate comparison; tips to reduce energy use; and carbon impact.

Mr. Lewellen then explained PSO implemented a comprehensive gridSMART® project in its Owasso area, and expanded AMI and consumer tariffs in three additional locations. PSO has deployed AMI meters to approximately 14,500 customers in the original Owasso project area in 2011. Based upon the customer response and benefits of AMI stemming from this deployment, an additional 17,000 AMI meters were deployed in 2012 (1,000 University of Tulsa Campus, 6,500 Okmulgee, and 9,500 Sand Springs). Also, all customers with an AMI meter have access to the customer web portal. The approximately $13.2 million capital investment associated with these AMI deployments and in-home technology were in service and were being used by customers during the test year.

PSO gained operational experience with a variety of smart grid technologies including AMI, DA, VVO, consumer engagement, two-way communications, and back office system implementations. The Company gained a greater understanding of customer response on three fronts:

- customer benefits of deploying AMI technology;
- the potential impact of advanced consumer tariffs on customer energy consumption, peak demand and energy cost and how customers respond to pricing and enabling technology; and

- the potential impact of providing customer access to interval energy usage through an interactive customer web portal.

Mr. Lewellen then summarized the results that the Company has experienced from AMI and associated customer tariff deployments and how this information would be used in future deployments. PSO learned from the original Owasso project and subsequent AMI deployments that an integrated set of smart grid technologies and tariffs allows customers to reduce their energy and peak demand consumption, and save money on their monthly electric bills. This result was accomplished through a combination of technology and tariffs which provided customers with the information necessary to manage their electric usage. Customers served with smart grid technologies experienced service improvements in terms of faster order fulfillment and improved service reliability, which led to improved customer satisfaction.

Mr. Lewellen then detailed the customer service benefits that resulted from the AMI deployments. This result was driven by PSO's customer web portal, AMI meters, in-home technology, as well as the programs that PSO implemented which helped educate customers and achieve energy savings by taking advantage of TOD rates and air conditioner control programs.

Mr. Lewellen then detailed the operational benefits that resulted in the AMI deployment areas. The four AMI deployment areas helped PSO achieve operational benefits through AMI's functionality. PSO found that the ability to remotely connect and disconnect led to improved operational capabilities. The three metrics highlighted below summarize some of the operational achievements for remote operations in 2013 for 31,500 meters.

- o Average Number of Monthly Credit Disconnect Orders Completed – 320
- o Average Number of Monthly Credit Reconnects Completed – 310
- o Average Number of Monthly Connect/Disconnects Completed – 1,300

The operational benefits derived from the ability to connect or disconnect a customer remotely at the customer's property included the significant reduction in the time required to complete connection/disconnection orders, and establishing service to new customers quicker. The ability to remotely read meters helped improve billing accuracy and led to decreased meter estimations. Also, there is no longer a need to send meter readers to a customer yard on a monthly basis. However, PSO will still need occasional access for meter testing and maintenance. The following metrics highlight some of the operational benefits achieved through this ability in 2013:

- o Average Number of Monthly Remote Reads – 31,500
- o Average Number of Monthly Saved Truck Rolls – 1,900

- Average Number of Monthly Hazards Avoided – 1,100

Mr. Lewellen detailed the reliability benefits that resulted from the AMI deployments.

The two-way communications capabilities of AMI allowed PSO to achieve improved customer reliability by alerting PSO to potential reliability issues. For example, temperature alerts are sent when the AMI device detects large variances in temperature due to rare instances of excessive heat in the meter. In 2013, 37 temperature alarms were investigated, which led to 21 proactive repairs of meter blocks in various stages of failure before the customer was even aware of any problem.

Similarly, the AMI meters can help detect power outages. PSO has the ability to quickly determine if service is available to a customer with a disconnect switch and to verify that service has been restored following an interruption. PSO is working on integrating AMI with outage management systems to be better equipped to detect power outage locations.

Finally, AMI provides voltage interval reading capability. This functionality helps to support voltage optimization and to identify problems before they occur. Mr. Lewellen discussed the customer web portal, testifying that it gives customers timely consumption and pricing information, along with tips on how to save energy. The customer web portal is seamlessly integrated into the existing customer account log-in process, which means customers log in to their existing account on PSOklahoma.com. If they have an AMI meter and log in to their existing account, they are automatically presented with their usage information. Customers also have the ability to link directly to existing PSO energy efficiency programs currently being offered to help manage their energy usage.

At the end of 2013, PSO upgraded its customer web portal to include Green Button functionality. Green Button is an industry-led effort to provide customers with secure and easy access to their energy usage information from their AMI meters in both a consumer-friendly and computer-friendly format via a "Green Button" on PSO's customer web portal. Through October of 2013, over 2,200 active customers have used the customer web portal. PSO has found that customer web portal usage increases after customers receive education material.

Mr. Lewellen then discussed PSO's AMI deployment program, explaining that PSO plans to deploy approximately 522,000 AMI meters throughout its entire service territory over a three-year time period. This number of AMI meters is in addition to the approximately 31,500 already in-service. This deployment will allow PSO to implement consumer programs, as well as a Pre-Pay Billing Program, which PSO anticipates will be part of a future formal application with the Commission in 2014, as discussed later.

PSO's proposed AMI Deployment Program differs from its previous smart grid technology deployments in that it is only for AMI, consumer tariffs, and the customer web portal to take advantage of usage information. PSO's proposed AMI deployment is a prudent investment, as it provides customers access to the benefits of AMI currently experienced by most other electric consumers in Oklahoma.

This AMI deployment will also serve as the platform for voluntary consumer programs designed to engage customers to reduce energy usage and demand, the customer web portal, pre-pay billing functionality, and future gridSMART® deployments.

Mr. Lewellen testified that PSO is choosing now for the timing of this deployment because PSO wants to extend the benefits of AMI to customers in its service territory; benefits that customers served by other utilities in Oklahoma are already receiving and that PSO customers are now expecting. Electric utilities continue upgrading their customers' analog electric meters with digital 'smart' meters, according to the latest report from IEE, an Institute of the Edison Foundation. As of July 2013, nearly 40 percent of U.S. households have a smart meter. In May 2012, only 33 percent of households had smart meters. Now is the perfect time for PSO's proposed deployment, as the costs of AMI meters have decreased approximately 25 percent in the last three years.

Mr. Lewellen then provided an overview of PSO's AMI implementation plan. As part of this deployment, all components of the project, including contractors and meter and network suppliers, will be competitively bid to ensure the lowest cost is achieved. PSO will also provide customer enhanced communications to help educate customers on the usage and benefits of AMI. Prior to deploying AMI meters in the different PSO communities, PSO plans to communicate with our customers through community meetings, customer letters, call dialer messaging, door hangers, and post card mailings. A period of less than three years is not sufficient to accomplish the full scope of PSO's proposal.

The estimated total project capital cost is approximately $132.9 million. In addition to capital cost, over the first three years an estimated $15.5 million in incremental O&M is also needed. The $132.9 million amount includes $13.2 million in capital investment included in the test year (as previously mentioned in my testimony).

The AMI portion of the project cost is approximately $119.7 million in capital and $14.5 million in incremental O&M over the three-year deployment period. Figure 8 summarizes the AMI portion of the project cost.

Figure 8

AMI Deployment Cost		
Component	**Capital**	**O&M**
gridMGMT	$600,000	$3,300,000
AMI Meter	$87,000,000	$6,300,000
AMI Network	$24,900,000	$1,600,000
AMI IT	$7,200,000	$3,300,000
Totals	**$119,700,000**	**$14,500,000**

Mr. Lewellen then reiterated the benefits that customers should experience once they have AMI. PSO customers receiving AMI as part of this program should experience benefits similar to those experienced by PSO's customers that were part of the prior AMI deployments. The following list is a summary of those benefits.

- Customer web portal for consumer education
- Consumer energy savings
- Remote connect/disconnect capability
- Power outage detection
- Remotely read meters on demand
- Voltage interval reading
- Alarms, such as temperature

Mr. Lewellen also described additional benefits that should be achieved through the implementation of AMI in PSO's service territory. AMI provides both quantitative and qualitative benefits. From a quantitative perspective, during the deployment, the expected O&M savings associated with labor, vehicles, and associated overheads will be approximately $5.0 million. With automated meter reads, AMI nearly eliminates estimated bills, leading to greater billing accuracy, which also leads to improved customer satisfaction. For instance, when a customer wishes to terminate service, the AMI meter can be read remotely and a final bill sent without delays caused by manual reads. Similarly, AMI meters equipped with a remote service switch enable power to be turned on or off remotely. As a result, a customer moving in can have service turned on in minutes, rather than waiting until the next business day.

AMI also provides customers with the ability to view their energy consumption on a more granular level; typically multiple data points per day will be provided. This data can be useful for customers, as it can help provide a better understanding of their energy usage and consumption behavior. The availability of this data can also enable customers to participate in consumer programs. Such programs are designed to reduce peak demand and energy usage, thereby allowing customers to benefit through potential savings on energy costs.

In addition, AMI provides billing and call center efficiencies that will enable employees to address more inquiries in a more expeditious manner. Customers should experience fewer billing issues due to the elimination of estimated meter reads. Call center representatives will have real-time access to meter data, which will help them discuss actual usage information with customers. When a customer calls about a power outage, the real-time access also will enable call center representatives to determine whether the outage is due to a PSO-outage or to an issue on the customer side of the meter.

From a reliability perspective, when an AMI meter detects a loss of voltage, a message is sent indicating the customer has lost power. PSO can use this information in conjunction with customer telephone calls to help determine the extent of the outage. Also, meters can be queried (pinged/polled) to get an indication of whether a customer has power.

This indication is useful to troubleshoot customer issues and to verify restoration following an outage.

Mr. Lewellen detailed the tariffs and associated consumer programs that PSO will implement as part of its proposed AMI deployment. This would include a TOD tariff and pilot either a DLC or Residential Peak Time Rebate (RPTR) tariff associated with peak demand reduction. The TOD (SMART Shift) tariff will send price signals about the costs of providing power in the on-and off-peak seasons and at different times of day during the peak season. This tariff provides an incentive for customers to shift electric use from peak periods to non-peak hours, which permits customers to save on energy costs. PSO's plan is to keep the existing two-tier residential TOD tariff and discontinue the CPP (SMART Shift Plus) tariff based upon the lack of customer participation and benefits experienced during the last two summers.

Under the pilot DLC (SMART Cooling) or RPTR tariff, PSO would provide enrolled customers incentives to control their electric usage during certain hours during the peak months.

Figure 9 summarizes the consumer program costs.

Figure 9

Consumer Program Costs*				
Program Component	**2014**	**2015**	**2016**	**Totals**
Customer Education	$300,000	$500,000	$1,250,000	**$2,050,000**
Program Management	$250,000	$500,000	$750,000	**$1,500,000**
Thermostat Rebate	0	$400,000	$2,000,000	**$2,400,000**
Totals	**$550,000**	**$1,400,000**	**$4,000,000**	**$5,950,000**

***Program costs are based on estimated customer enrollments during the three-year deployment period of 0 in 2014, 2,000 in 2015, and 10,000 in 2016.**

Mr. Lewellen also described the anticipated benefits that customers will receive from participating in the consumer programs. Based on the pilot results for the SMART Shift Program, PSO saw that the participants in this program saved an average of approximately $8 per month during the five-month summer season. PSO anticipates similar savings for customers that participate in this program following the AMI deployment. Similarly, PSO saw that participants in the SMART Cooling Programs save $2.50 per air conditioning unit controlled per event.

Finally, Mr. Lewellen briefly outlined PSO's long-term objective once AMI is fully deployed. PSO envisions an AMI deployment as a platform for the implementation of other consumer programs and gridSMART® technologies. As technology advances, the electric utility industry has the opportunity to enhance the way it does business to provide additional customer benefits. Mr. Lewellen concluded that PSO has proven that AMI offers a number of benefits through the successful implementation of this technology in four different areas. PSO plans to continue this effort with the deployment of AMI throughout the rest of its service territory. The AMI deployment, which includes approximately $132.9 million investment and $15.5 million in incremental O&M, will take three years to complete, and will provide benefits to both PSO and our customers.

Summary of Rebuttal Testimony of Derek S. Lewellen

Mr. Lewellen responded to various statements and recommendations in the Responsive Testimonies of Tonya Hinex-Ford representing the Public Utility Division (PUD) of the Oklahoma Corporation Commission (OCC or Commission), and Barbara R. Alexander representing the American Association of Retired Persons (AARP). Overall, Ms. Hinex-Ford recognized the customer benefits of a full AMI deployment, including a customer web portal for consumer education, consumer energy savings, remote connect/disconnect capability, power outage detection, remotely read meters on demand, voltage interval reading, and temperature alarms; and notably she testifies that "the smart grid is believed to increase both the reliability and efficiency of the grid." (at 8-9, 12). Ms. Hinex-Ford recognized the benefits of AMI throughout her testimony, but concluded that PUD does not recommend approval of the project and instead emphasizes three items that should be contained within future proposals. Specifically, she recommends that the following elements be included in subsequent proposals: "guaranteed savings on O&M expected savings associated with labor, vehicles, and overheads; effective pricing/technology combination for customers; and for those customers that do not have internet access and have an AMI meter, a Home Energy Report be made available free of charge specifically to LIHEAP and Senior Citizens."

Mr. Lewellen testified PSO's proposal satisfies each element set forth by Ms. Hinex-Ford. Ms. Hinex-Ford highlighted the $5.0 million in operations and maintenance (O&M) savings described in direct testimony that will result from labor, vehicles, and overheads during the deployment period. PSO will guarantee this $5.0 million in O&M savings during the three-year deployment period and an additional $6 million in O&M savings in the first year after deployment, which totals $11 million in guaranteed savings over four years.

PSO's Meter Revenue Operations (MRO) organization currently has 111 field employees and contractors (59 meter reader and 52 field specialists) that perform meter reading and field orders (i.e. meter connect/disconnect orders, replace single-phase meters, and move in/out orders). Once PSO has completed its AMI deployment, PSO's MRO organization would be reduced by approximately 83 field employees. This reduction of 83 field MRO employees equates to a 75 percent reduction in existing staffing, and would be accompanied by a similar reduction in vehicles and overheads. This is approximately $47.6 million of loaded labor and vehicle savings on a net present value (NPV) basis over a 15-year period.

Mr. Lewellen also testified that PSO's plan addresses Ms. Hinex-Ford's requirement of effective pricing and technology combinations. As discussed in his Direct Testimony, PSO proposes to carry forward from the pilot projects both the Time of Day (TOD) and

Direct Load Control (DLC) pricing offerings because they resulted in the highest participation and savings for customers during the pilot phases. These two voluntary programs also allow customers the greatest flexibility to participate in either one or both of the programs. In terms of technology, PSO proposes to offer a thermostat rebate program to assist customers in purchasing a qualifying programmable thermostat, compatible with the programs. The TOD (SMART Shift) tariff will send price signals about the costs of providing power at different times of day during the peak season. This tariff provides an incentive for customers to shift electric use from peak periods to non-peak hours, which permits customers to save on energy costs, and it is easy for customers to understand.

Under the DLC offering, PSO will provide enrolled customers with incentives to allow PSO to control their Air Conditioning (A/C) during peak periods. The DLC tariff provides a customer with a $2.50 bill credit per A/C unit that is controlled per event. The customer can opt out of the event at any time via their thermostat without penalty. PSO can call up to 16 events Monday through Friday during the months of June through September and each event can last no longer than 5 hours. The customer has the opportunity to receive up to $40 per A/C unit controlled per on peak season.

PSO proposes to offer a thermostat rebate program to assist customers who choose to enroll in the TOD and/or DLC program. The rebate will apply to a qualifying programmable thermostat. For 2015, PSO will offer rebates totaling $400,000 and $2,000,000 in 2016, based upon the forecasted customer enrollments. The rebate will be $150 per thermostat with a maximum of two rebates per household. Once the pilot phase is completed, PSO will continue the rebate program in some form.

Offering rebates versus company-owned devices is based on the pilot experience of PSO owning, installing, and maintaining in-home technology, and market research that indicates this is the prevailing approach in the market. As discussed in the discovery response to AARP 4-2, the following is just a sampling of utilities employing the rebate approach: ComEd, National Grid, San Diego Gas & Electric, Pacific Gas and Electric Company, Southern California Edison, Florida Power & Light Company, Xcel Energy, and Austin Energy.

In providing rebates for commercially available thermostats, PSO is not directly competing with HVAC companies on the installation and maintenance of thermostats. This approach also reduces the ongoing costs that would otherwise be associated with PSO installing, owning, and maintaining thermostats. Further, customers owning and maintaining the in-home technology should be more engaged in the program.

Mr. Lewellen testified that all of the programs will be available during the implementation of AMI meters. That is, once an AMI meter is installed on a customer's premises, beginning in January, 2015, the customer will be able to enroll in one or both of the programs for the 2015 on-peak season.

Mr. Lewellen agreed with Ms. Hinex-Ford's recommendation of making a Home Energy Report, upon request, available free of charge to those customers without internet access, namely LIHEAP eligible customers and Senior Citizens.

Regarding Ms. Alexander's assertions, Mr. Lewellen argued that PSO's proposal yields significant benefits for customers. PSO's program will generate savings that include, in part, reductions in bad debt, theft, and consumption on inactive meters, billing and call center reductions, energy reductions associated with a Pre-Pay program, and energy and peak load reductions stemming from tariffs and consumer programs. Together, the quantifiable savings result in a positive net present value (NPV) of over $7 million. Further, there are numerous customer quality of service benefits that are not easily quantifiable but undoubtedly beneficial to customers.

Figure 2 summarizes the 15-year (life of assets) net present value for the revenue requirement and quantifiable benefits, which shows AMI produces net benefits to customers of $7.4 million. This analysis does not include the qualitative benefits.

Figure 2

AMI Program	15-year Net Present Value
Revenue Requirement	($176.5 million)
Consumer Programs	($16.2 million)
Avoided Capacity Additions	$113.6 million
Field Labor/Fleet	$47.6 million
Bad Debt, Theft, Consumption on Inactive Meters, and Obsolete Meter Avoidance	$35.3 million
Billing/Call Center	$0.7 million
Other	$2.9 million
Total	$7.4 million

PSO projects that due to the demand and energy reductions associated with the Pre-Pay and consumer programs, PSO would be able to effectively eliminate the need for approximately 82 MW of capacity additions. If Pre-Pay and consumer programs were not implemented, these capacity additions would be projected to cost customers approximately $113.6 million on an NPV basis over a 15-year period. PSO plans to implement a voluntary Pre-Pay Billing Program and will be seeking approval later this year. This is contrary to the testimony of Ms. Alexander who incorrectly interpreted our decision not to deploy Pre-Pay in 2011 in a pilot area as a decision to never go forward with the program.

Based upon the pilot results and the ability to market to additional customers, PSO estimates that 8 percent of the eligible customers will participate in voluntary AMI-enabled tariffs and customer programs (Time-of-Day and Direct Load Control Programs) that provide the customer the opportunity to save money by shifting usage from high-cost periods to low-cost periods or by reducing demand at times of PSO company peaks in the first five years of the program. Based upon the pilot results, a conservative average of 1.8 kW reduction during the peak period was realized for each residential customer participating in the DLC program and 0.3 kW for the TOD program.

The $47.6 million on NPV basis of savings related to the field labor and fleet reductions are from the reduction in labor, vehicles, and overheads that will occur because of the installation of AMI meters.

With respect to the $35.3 million of savings related to bad debt, theft, and consumption, the implementation of AMI will allow for a reduction in costs related to bad debt, theft, and consumption on inactive meters through its remote disconnection capability. PSO believes that it can reduce bad debt by approximately 50 percent, amounting to $13.8 million in savings. Obsolete meter avoidance yields savings of $1.2 million by avoiding the cost of replacing meters during the deployment period that had reached the end of their useful lives. By replacing these meters with an AMI meter during deployment, the replacement costs associated with these meters are avoided. Also, having the ability to remotely disconnect meters allows for the reduction in consumption on inactive meters, producing savings of $0.4 million. Combined, the reduction in theft, bad debt, consumption on inactive meters, and obsolete meter avoidance will result in approximately $35.3 million of benefits on an NPV basis over a 15-year period.

AMI provides billing and call center efficiencies that will enable employees to address more inquiries in a more expeditious manner. Billing and call center efficiencies would result in approximately $0.7 million of benefits on an NPV basis over a 15-year period.

"Other" benefits include a reduction in injuries and motor vehicle accidents by having 75 percent fewer field employees. Also, AMI provides a benefit to the utility in providing a more automated, lower-cost means of obtaining and managing customer interval usage data needed for ratemaking, planning, special billing, and demand response program implementation and evaluation. This in turn could lead to a reduction in capacity and reliability planning resources. The 15-year NPV associated with these is approximately $2.9 million.

There are also a number of qualitative benefits for customers once AMI has been deployed. The following list provides additional information pertaining to the customer benefits resulting from AMI.

- Increased customer education and satisfaction due to Customer Web Portal and related tools – The customer web portal contains customer education information, as well as decision-making features to help customers save on their electric bills:

- Power outage detection through real-time access:

- Additional and improved metering activities:

- Quality of Service improvements as a result of AMI's functionality:

- Environmental impacts can be mitigated:

- As a platform for the future, additional AMI functionality that has yet to be developed will lead to additional benefits:

  PSO provided detailed benefit information stemming from AMI's usage in PSO's pilot, as well as the anticipated benefits of PSO's proposed AMI deployment in my direct testimony, discovery responses, as well as other documentation. The only information included in Rebuttal Testimony not previously provided is PSO's commitment to the $11 million of guaranteed savings, the addition of the avoided capacity costs into the NPV analysis, and providing additional details for customer program enrollments provided in direct testimony or discovery response.

  The following list highlights information provided in regard to AMI benefits:

- Benefits of AMI – Company witness Lewellen's direct testimony, pages 8-9, 13-15, and 21-24;

- Cost/benefit analysis – Discovery responses AG 5-7, AARP 1-1, AARP 1-2, and AARP 2-10;

- Analysis of pilot results – Company witness Lewellen's direct testimony, pages 9-12, discovery responses AARP 1-5, AARP 2-4, AARP 2-12, and AARP 4-9;

- Additional AMI deployment cost information:

  - Customer engagement costs – discovery responses AARP 1-20, and AARP 1-4;

  - AMI post-deployment costs – discovery responses AG 5-7, and AARP 1-42;

  - Customer education costs – discovery response AARP 4-3; and

  - AMI deployment project management costs – Company witness Williamson's Exhibit AJW-3, and discovery response PUDLS 2-8.

As part of discovery response AARP 1-3, PSO shared with the AARP its plan to track costs and benefits as a result of PSO's proposed AMI deployment.

Mr. Lewellen testified that PSO's analysis of the pilot programs is complete and valid. From a utility perspective, a major goal of these consumer programs is to lower costs and the peak demand during peak periods of high generation cost. Customers participating voluntarily saved money on their electric bills by reducing electric usage when tariff prices were highest during peak periods when PSO's cost to serve customers is at its peak, and shifted their usage to lower tariff price periods when PSO's costs to serve customers is lower. These customer benefits from the consumer programs will be extended to all PSO customers on a voluntary basis with the successful implementation of AMI throughout PSO's service territory. In addition to these savings, all PSO customers save from the reduced cost of PSO avoiding the costly addition of new power plants.

Mr. Lewellen agreed with Ms. Alexander's assertion that there is no evidence that customers participating in the tariff programs lowered their annual usage because the SMART Shift and SMART Shift Plus Programs are not intended to be energy reduction programs, but are intended to provide customers an additional optional pricing program under which participants have the opportunity to lower their electric bill by shifting usage from higher-priced time periods to lower-priced time periods.

Ms. Alexander indicated that she has concerns with PSO's DLC pilot, but is generally in favor of a DLC program that relies on customer credits and rewards. Mr. Lewellen testified that although implementation of DLC programs without AMI is being piloted at a number of utilities, in its present form, customers would not be able to participate in any of the other AMI-enabled customer programs or receive any of the benefits associated with AMI that I have discussed in detail. Without AMI meter data, it is more difficult to measure the demand response of the program, and does not provide near real-time customer feedback on energy changes. Customers are not provided the near real-time feedback on changes made to reduce or shift energy usage during peak periods.

For example, through use of an AMI meter, customers have access to both current and historical interval data, and the ability to participate in TOD tariffs. This interval data allows customers the ability to make more informed decisions about their electricity usage and the resulting impact on their electricity bill.

In respect to shifting the costs to customers, with the rebate covering the majority, if not all the cost of the thermostat, costs are not shifted to customers and there should not be a barrier for any customer class to participate in the programs. For customers to participate in the TOD tariff, in-home technology is not required. In addition, customers have full control of their thermostats, even during a DLC event. Customers can over-ride the controls and opt not to participate in the event without penalty.

Ms. Alexander states that PSO has not provided any outreach and education plan as part of its filing that would suggest that PSO would have a higher participation rate (at 19) than what it has projected. Furthermore, Ms. Alexander recommends that PSO improves its education and outreach program based upon the pilot survey responses and program evaluation (at 23).

When this case was originally filed, PSO's customer education and communication plan was still in development. As stated in the Application, PSO was mandated by the Commission to file this base rate case no later than January 18, 2014. However, since the filing was made, PSO has completed its initial customer education and communication plan, which he has included as EXHIBIT DSL-1R. Based on PSO's experience and lessons learned from the pilot, as well as information gleaned from PSO's sister companies and other utilities that have deployed AMI, we are confident that our plans to reach customers will be effective, proactive, and engaging. During the pilot program, the opportunity to provide customer education on programs was limited. For example, mass media such as newspaper, radio and television, or public events such as home and garden shows, could not be used since the message would be shared with a much larger group of ineligible customers, which could have potentially created confusion. The customer education program will help our customers understand our proposed AMI deployment, what they can expect once they have AMI, how they can participate in AMI-enabled tariffs and programs, processes available if they have questions or concerns, and the expected benefits of AMI.

Regarding PSO's disconnection process, Ms. Alexander is concerned that the installation of AMI may result in the degradation of consumer protections associated with disconnections for nonpayment (at 30). For example, Ms. Alexander believes that the installation of AMI would eliminate any required premises visit, or in-person contact attempts (at 28), which she feels is one such consumer protection.

First and foremost, as PSO discussed in discovery response AARP 1-21, PSO's procedures regarding disconnection for nonpayment strictly follow the requirements set forth in OAC 165:35-21 [*sic*] Disconnection of Service and for those customers with AMI meters, Order No. 589969 of Cause No. PUD 201100083. For residential customers, regardless of the type of meter they have, if a bill is not paid by the due date, the first disconnect notice is mailed to customers with their next month's bill. This notice satisfies the minimum ten-day requirement found in OAC 165:35-21-20(b). To satisfy the minimum 48-hour notice required by OAC 165:35-21-20(c), a second disconnection notice is scheduled to be mailed 12 business days after the first notice. Additionally, though not required by the Commission's Electric Rules, PSO contacts customers by telephone 48 hours prior to disconnect to notify them that they need to contact PSO regarding their service. When the customer contacts PSO, they are then informed that their service is subject to disconnect.

Ms. Alexander recommends that the Commission should reject PSO's attempts to recover the costs of DA and VVO because of what she perceives to be a failure on the part of PSO to provide performance results that show that these technologies will provide benefits to PSO's customers (at 8). However, Mr. Lewellen testified that the Owasso pilot did create the results and benefits originally anticipated by PSO. The Owasso pilot results, along with the south Tulsa DA project and information from other utility experiences, will be used by PSO to develop an overall grid management strategy later this year. For DA, PSO originally installed a first generation distribution automation scheme in South Tulsa that has been operating very successfully for over 5 years, allowing PSO to avoid approximately 1.3 million minutes of customer outage minutes.

Concerning VVO, the purpose of the Owasso pilot was to develop VVO technology with an industry leading company and evaluate their solution versus other solutions being developed across the electric utility industry. A number of improvements were identified with the anticipation of improving the 2013 summer performance. Enhancements to the VVO system were made in the spring of 2013 and another day on/off evaluation was done in the summer of 2013, which included modeling over 150 million data points by PNNL. The final report for the 2013 evaluation was delivered in March 2014 and showed significant performance improvements between the 2012 evaluation and the 2013 evaluation. These results highlight the potential benefits of a well-functioning VVO system.

Mr. Lewellen concluded that no party provided any valid, unrebutted reason why PSO's AMI deployment should be delayed. For the last three years, PSO has successfully installed, operated, and evaluated multiple AMI pilot areas through a methodical, phased-in approach. Because of this, we have benefitted from lessons learned and added experience with the new technologies, resulting in tremendous benefits for our customers. PSO's approach has also allowed us to realize a significant drop in meter prices (over 25 percent) in the last three years. As I already discussed, the all-in cost per customer of our AMI program is 21% less than that approved for OGE's AMI program. With the penetration rate of AMI meters across the country exceeding 50%, now is the time for PSO to move forward with AMI for the benefit of our customers.

Summary of the Direct and Rebuttal Testimonies of 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 several known and measurable ratemaking adjustments to the test year amounts making up PSO's overall rate base and cost of service. His EXHIBIT RWH-1 provided a listing of the adjustments he sponsored. In addition, 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 201000050 along with the recovery of the storm maintenance expense caused by a large storm that hit PSO's service territory in the last month of the test year, July 2013. He also briefly discussed two recent ice storms that occurred in December 2013.

Mr. Hamlett adopted the testimony of Mr. Andrew J. Williamson. Mr. Williamson'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 July 31, 2013. He presented and supported various application package schedules along with certain supplemental package schedules.

In addition, Mr. Williamson supported the incremental annual revenue requirements associated with PSO's [*sic*] initiative to fully deploy advanced metering capabilities to PSO's [*sic*] customers beginning in 2014 and to be completed by the end of 2016.

According to Mr. Williamson, the application package (AP) Schedule B-01 showed a revenue deficiency of $37,305,012 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	$1,865,522,788
Rate of Return	F-01	7.94%
Operating Income Requirement		$148,122,509
Pro-Forma Operating Income	B-02	$125,363,063
Revenue Conversion Factor		1.639100
Revenue Deficiency		$37,305,012

Mr. Williamson testified the Company's Oklahoma jurisdictional pro-forma rate base at July 31, 2013, was $1,860,914,699 (AP Schedule B-02, Lie [*sic*] 21, col. 7). The Oklahoma jurisdictional pro-forma operating income was $124,742,704 (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 6.70% (AP Schedule B-02, line 23, col. 7).

Mr. Hamlett's rebuttal testimony responded to proposed adjustments to PSO's base rate revenue requirement recommended by other parties to this case.

According to Mr. Hamlett, the Staff of the Corporation Commission of the State of Oklahoma (OCC or Staff) recommends a net revenue decrease of $7.3 million as reflected on Staff's Section A Schedule, Line 7. This Schedule is sponsored by Mr. Robert C. Thompson. The Office of the Attorney General's (AG) witness Mr. Edwin C. Farrar recommended a net revenue increase of $16.3 million as shown on Exhibit ECF-3, Page 1, Line 18. In his rate design testimony filed on May 7, 2014, Mr. Farrar stated that he cannot recommend an increase to depreciation rates that the Company has requested and also cannot recommend an overall increase in rates. He did not file any schedules updating his overall recommended revenue changer. Oklahoma Industrial Energy Consumers (OIEC) witness Mr. Mark E. Garrett recommended a $22.2 million net revenue decrease as shown on Exhibit MG-2, Line 36. None of the three parties recommends adoption of PSO's proposed AMI rider. Thus, included in their recommendations is the costs of PSO's AMI investment through the end of January 2014.

PSO had removed these costs from base rates and included them in its proposed AMI rider. The OCC Staff and AG both recommend that vegetation management costs be removed from a reliability rider and included in base rates. The amounts above do not reflect this recovery change and if adopted by the Commission, base rates would need to reflect these additional costs. For example, Staff's $7 million decrease would change to a base rate increase of $8 million while the reliability rider would decrease by $15 million. After all this recover movement, the net result is a $7 million overall decrease in customer rates. From a customer perspective, they would see an increase in base rates, while the rider would decrease by an equal amount ($8 million base rate increase less $15 million rider reduction). Mr. Hamlett in rebuttal testimony addressed both rate case and operating income. Topics covered by Mr. Hamlett's rebuttal regarding rate base included electric plant, accumulated depreciation, prepayments, fuel and materials and supplies inventories, customer deposits, accumulative deferred income taxes, cash working capital, capitalized incentives, regulatory assets for the July 2013 storm and existing meters.

Rebuttal testimony regarding operating income included PSO payroll and payroll related taxes, ad valorem tax expense, supplemental executive retirement plan expense, depreciation and amortization expense, as well as various other expense items.

Mr. Hamlett recalculated PSO's total company revenue requirement (RWH-8R) which shows the net revenue deficiency of $42,040,649.

<u>Summary of the Direct Testimony of Gary C. Knight</u>

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

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 owns approximately 15.6% of and operates the Oklaunion Power Station, located in Vernon, Texas.

Excluding other capacity entitlements that are used to meet the minimum Southwest Power Pool reserve margin requirement, PSO owns a net generating capacity of approximately 4,433 MW. Based on fuel type, PSO's generating units are approximately 24% (or 1,043 MW) coal-fired capacity and 76% (or 3,390 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 generation 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 sharing 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, there are five organizations that report through the AEPSC Executive Vice President of Generation and are responsible for providing services and support to PSO. These five groups are the Generating Assets (GA) group, Engineering Services (ES), the Projects, Controls, and Construction group (PCC), Fuel Emissions & Logistics (FEL), and Business Services.

Mr. Knight described the five organizations as follows:

- The <u>Generating Assets</u> organization is involved directly in the operation and maintenance of the power plants in each of the operating companies owned by AEP. This group is comprised of the individual operating company Generating Asset Vice Presidents and the Fleet Operations Vice President. The operating company vice presidents operate as an interface between the operating company and the Generation organization.

    - The Fleet Operations group within the GA organization is responsible for fleet optimization, operational excellence, technical skills training and field services. In addition, the Fleet Operations group manages and oversees the day-to-day operation and maintenance of Indiana Michigan Power Company's generating assets.

- <u>Engineering Services</u> 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.

- <u>Projects, Controls, and Construction</u> is responsible for the planning and execution of larger capital projects at the power plants. PCC 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.

- <u>Fuel Emissions & Logistics</u> is responsible for purchasing and delivering suitable fuels and consumable products to PSO's generating plants. FEL also manages the emissions credits of the generating fleet.

- <u>Business Services</u> 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 test year generation non-fuel O&M was consistent with historic non-fuel O&M levels.

Both the actual non-fuel O&M of approximately $74.7 million and the adjusted test year O&M of approximately $73.1 million is lower than the prior three calendar year average of $80.7 million. The downward trend in incurred non-fuel O&M can be partially attributed to cost savings and efficiency gains implemented by PSO, as well as the timing of major outages for PSO's generating fleet.

Mr. Knight provided an overview of general projects that had been added to plant in service. According to Mr. Knight, PSO added approximately $97.5 million to generation plant in service since Cause No. PUD 201000050 for the period September 1, 2010, through July 31, 2013. Of the total generation plant in service addition of $97.5 million, approximately $58.8 million is associated with major capital projects that had a cost of greater than $500,000. The remaining balance of approximately $38.7 million of the total $97.5 million of generation plant in service was associated with a combination of individual production plant blanket (PPB) capital blanket 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 remains 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.

Summary of the Direct and Rebuttal Testimonies of 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 change to PSO's Southwest Power Pool Transmission Cost (SPPTC) tariff and the tariff to recover PSO's Advanced Metering Infrastructure (AMI) project.

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 change to PSO's Southwest Power Pool Transmission Cost (SPPTC) tariff and the tariff to recover PSO's Advanced Metering Infrastructure (AMI) project.

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 the [*sic*] AMI tariff, attached as Exhibit JOA-8, is designed to recover the incremental revenue requirement associated with PSO's three-year plan to deploy AMI to customers throughout its service territory. The AMI tariff, applied on a per-meter basis, will be implemented the first billing cycle of the month following the OCC's final order in this proceeding and will remain in effect until the first base rate case subsequent to the full implementation of AMI, at which time the costs will be included in PSO's base rate revenue requirement.

The AMI tariff will apply to all customer groups except for those customers at Service Levels 1 and 2. Customers taking service at these two service levels currently have the technology that will be deployed to the remaining customer population of PSO.

Mr. Aaron further testified that the incremental AMI revenue requirement will be allocated to customers based on a meter cost allocation reflecting the meter costs of PSO's AMI meter technology.

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 revised SPPTC tariff provides for the recovery of SPP Schedule 9 and Schedule 11 costs not recovered in its base rates. Schedule 9 costs for PSO's existing transmission investments will continue to be reflected in its base rate revenue requirement.

PSO's requested AMI tariff provides for the recovery of the incremental revenue requirement associated with PSO's AMI deployment until a subsequent base rate proceeding after PSO's full AMI deployment. The tariff will be based on the estimated annual incremental revenue requirement assuming a three-year deployment with a true-up to ensure no over- or under-recovery of PSO's AMI costs.

Mr. Aaron filed rebuttal responding to the issues of Oklahoma Corporation Commission (OCC or Commission) Public Utility Division (PUD) Staff witness Luis Saenz, Oklahoma Industrial Energy [*sic*] Consumers (OIEC) witness Mark Garrett, and Wal-Mart witness Steve Chriss as shown in the table below.

	PUD Staff Luis Saenz	OIEC Mark Garrett	Wal-Mart Steve Chriss
Transmission Allocation	X	X	
Distribution Plant Classification	X		
SPPTC Tariff		X	X
Cost-of-service Revenues		X	
Cost-of-service Demands		X	
Standby/ Supplemental Tariff			X

According to Mr. Aaron, the 12 CP transmission allocation methodology appropriately allocates the cost PSO is incurring to provide transmission service to the customer class responsible for that cost. The SPP bills PSO for transmission services on a 12 CP basis as mandated by the SPP OATT. PSO's requested 12 CP transmission allocation is consistent with cost recovery and rate principles whereby rates are designed to recover the costs incurred to serve each respective class. Use of the 12 CP does not alter or confuse PSO's price signals to customers.

Mr. Aaron testified that PSO has complied with the requirements set forth in Paragraph 6 of the Findings of Fact in Order No. 591185 in Cause No. PUD 201100106.

Yes. PSO has complied with the requirements of the above-cited order. Further, it should be noted that the elements identified in Paragraph 6 of the Findings of Fact are essentially the same as those listed in Paragraph 5 of the Findings of Fact. Paragraph 5 governs the annual true-up filing for the redetermination of the SPPTC factors that PSO has twice made (September 4, 2014 [*sic*], and August 30, 2013). Both filings were sufficient to result in PUD's approval of annual factors. Although both filings were made within Cause No. PUD 201100106, no party questioned the content of the filings or the proposed factors.

Mr. Aaron responded to Mr. Garrett's alleged error in PSO's cost-of-service study by stating PSO filed cost-of-study (1) accurately reflects the allocation of cost to the customer class responsible for the cost, (2) accurately reflects the revenues collected by PSO with its existing approved tariffs, and (3) can be readily utilized in the determination of the customer class revenue requirement and rate design. Mr. Garrett's recommendation to adjust PSO's demand allocations in the cost-of-service study because of his calculated revenue shortfall should be denied. His testimony (page 10, line 7 through page 14, line 4) regarding the errors, mismatches and misallocations in PSO cost-of-service study should be dismissed.

<u>Summary of the Direct Testimony of Rajagopalan Sundararajan</u>

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 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 is a wholly-owned transmission subsidiary of AEPHoldco. AEP Transmission Company, LLC serves as a holding company for AEP's seven transmission-only companies that were created to assist AEP's operating companies in developing transmission: 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. Also, with the advent of new technologies, 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, 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 $242 million in transmission assets, which otherwise would have been invested by PSO. Over the next five years, OK Transco plans to invest approximately $647 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 Mr. Bradish's Direct Testimony.

Mr. Sundararajan further testified that OK Transco was formed as one of seven AEP Transmission-only companies to undertake transmission development in the territories of several of AEP's operating companies. OK Transco was specifically formed to provide an alternate vehicle to construct, own and operate necessary transmission facilities on PSO's service territory in order 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 is a relief valve for PSO's transmission capital needs.

In the SPP, this allows AEP to continue to develop and own transmission investments on its systems without the need to novate to an unaffiliated party as is allowed under SPP Business Practice 7070.

Mr. Sundararajan provided an overview of FERC Order No. 1000 and that one of the most significant provisions is the removal of the federal right of first refusal (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 [*sic*] 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.

<u>Summary of the Rebuttal Testimony of C. Richard Ross</u>

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 addressed the Oklahoma Industrial Energy Consumers (OIEC) witness Garrett's assertion that the Federal Energy Regulatory Commission (FERC) approved SPP Open Access Transmission Tariff (OATT) expenses PSO seeks to recover through its SPPTC Tariff are not reasonable due to the fact that PSO has not intervened in any case to question the reasonableness of regionally funded third-party owned transmission projects in SPP, and that some SPP third party projects have experienced cost over-runs. Further, Mr. Ross addresses his allegation that PSO has not identified benefits (economic or otherwise), that third party upgrades and facilities provide to the regional grid and PSO's customers.

According to Mr. Ross, Mr. Garrett seemingly ignores the fact that through FERC's approval of SPP as a Regional Transmission Organization (RTO) and through FERC's approval of SPP's OATT, SPP has the required authority over transmission planning which encompasses all SPP transmission-owning members, including PSO. SPP selects transmission projects on a regional basis through a process known as ITP. This process identifies which transmission owners will build the project based on overall regional reliability and economic benefits. Additionally, FERC has given the SPP RSC authority to determine transmission project cost allocation to SPP customers. Because of the active participation of both the members of the regulatory bodies of the affected jurisdictions and the other stakeholders, FERC, in approving RTO proposals, accords appropriate deference to the open and extensive stakeholder processes which approach has been approved by the courts.[2]

According to Mr. Ross, the collaborative nature of the SPP Integrated Transmission Planning (ITP) process, and both AEPSC's and PSO's active participation in the SPP stakeholder groups provides significant oversight to the SPP transmission planning activities so that the projects constructed are needed and beneficial. Mr. Ross testified that he believed AEPSC's participation in the SPP Project Cost Working Group (PCWG) provides ongoing oversight over the actual cost of SPP transmission expansion projects. This oversight is in addition to the oversight by and through proceedings at the FERC and through the OCC's participation in the SPP Regional State Committee (RSC). Participation in SPP's processes is a reasonable and cost effective means for PSO to provide assurance that the cost of transmission projects built in SPP are reasonable and provide benefits to the regional grid and PSO customers and is a more productive process than spending time and resources [*sic*] at FERC through inefficient formal, legal challenges as suggested by Mr. Garrett.

Therefore, PSO believes the active participation at SPP provides a much more proactive, effective and efficient mechanism to monitor project costs and, if necessary, reevaluate the need for a project, rather than spending inefficient time and resources at FERC through the formal, legal challenges otherwise suggested by Mr. Garrett.

<u>Summary of the Direct Testimony of Robert W. Bradish</u>

Mr. Robert W. Bradish, employed by the American Electric Power Service Corporation (AEPSC) as Vice President – Grid Development for AEPSC testified on behalf of Public Service Company of Oklahoma (PSO).

According to Mr. Bradish, his testimony supports and provides an overview of the transmission projects and associated costs and benefits for capital projects constructed by the AEP Oklahoma Transmission Company, Inc. (OK Transco) to support Public Service Company of Oklahoma's (PSO or Company) request for cost recovery of projects constructed and owned by the OK Transco under the Southwest Power Pool (SPP) Federal Energy Regulatory Commission (FERC)-approved SPP Open Access Transmission Tariff (SPP OATT). Mr. Bradish's testimony:

- described the major factors that drive the need for new transmission investment including the federal, regional and corporate reliability standards;

[2] *See, e.g., Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283, at p.33 (2009) ; Policy Statement Regarding Regional Transmission Groups, 1991-1996 FERC Stats. & Regs. [sic] Preambles ¶ 30,976, at 30,872 (1993): *Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1062-63 (D.C. Cir. 2008) (quoting *Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083, at P 172, *reh'g denied*, 125 FERC ¶ 61,341 (2008)).

- Discussed how changes to current transmission planning reliability standards and other federal policies may affect PSO and its need to invest in new transmission infrastructure;

- Discussed major OK Transco projects and the methods used by SPP [*sic*] to determine which SPP [*sic*] entity constructs and owns transmission assets; and

- Discussed how the OK Transco projects will facilitate the development of a more robust and flexible transmission system that will enhance system reliability and provide access to lower energy costs for Oklahoma ratepayers.

<u>Summary of Direct and Rebuttal Testimonies of Andrew R. Carlin</u>

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, necessary, 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 levels of positions is to provide a target total compensation opportunity (base salary or base rate plus the target value of all incentive compensation) that is, on average, at the median of that provided for similar positions by companies of similar size and operating scope from which the Company needs to attract and retain employees.

PSO compensates all employees with both base pay and an annual incentive compensation opportunity. He refers to the sum of these two types of compensation as total cash compensation (TCC). In addition to base pay and annual incentive compensation, approximately 550 positions in the AEP system are provided with a long-term incentive compensation opportunity. He referred [*sic*] to the total compensation opportunity provided to these management and executive positions (TCC plus long-term incentive compensation) as total direct compensation (TDC). For positions that do not typically receive long-term incentive compensation, TCC and TDC are the same. In his testimony "Total Compensation" was used to refer to compensation that includes all applicable forms of incentive compensation for the positions in question, TCC or TDC, as appropriate.

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 as needed 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, including the target value of all incentive compensation, as the primary compensation benchmark for each position. Salary is also used as a point of comparison for all positions and TDC is also used 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 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. Survey information shows that annual incentive compensation is a significant and often substantial component of market competitive compensation for nearly every position. 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 annual incentive compensation for all positions and including long-term incentive compensation for high level exempt professional, managerial and executive positions. The value of any incentive compensation that both the market and the Company provide is also 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 increase to maintain a market competitive 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 2012, the Company's merit budget was 2.675 percent, which was less than the market median for all employee categories. For 2013, the Company's merit budget was 3.0 percent, which was the same as the market median. Since the Company's merit budgets were less than the market competitive level for several years and subsequently none of the annual merit budgets were significantly above market, the Company's pay levels did not keep pace with market competitive compensation during this period. The projected merit and general increase budget is 3.5% and 2.5% for 2014.

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. This compensation is market competitive on a base pay, target total cash compensation, and target total direct compensation basis. Annual and long-term incentive compensation is provided as part of this overall market competitive compensation package and does not represent an incremental expense to PSO's customers. Therefore, it is just and reasonable to include the full cost of the Company's compensation, including the target level of both annual and long-term incentive compensation, in the Company's cost of service.

Mr. Carlin filed rebuttal to discuss and dispute the individual mischaracterizations made by each of the other parties (Oklahoma Corporation Commission Public Utility Division (OCC PUD) Staff witness Seyedoff [*sic*], Oklahoma Attorney General (AG) witness

Farrar, and Oklahoma Industrial Energy Consumers (OIEC) witness Garrett) who seek to reduce PSO's reasonable cost of service and rate base. Most importantly, he discussed the fact that despite a myriad of criticisms of employees' Total Compensation Package, no party disputes the fact that this compensation is fair based on the market comparison studies that are the basis for the reasonableness of AEP's compensation.

To attract and retain the highly skilled and diverse workforce necessary to provide quality electric service to customers requires compensation to be at market rates. Otherwise, we could not attract these high quality employees to work with us in the first place; thereafter, if their compensation is reduced below market rates, they will leave or be dissatisfied. The parties' criticism of employee compensation is not based on how much the total compensation should be, but rather their views on how that compensation should be paid.

Mr. Carlin stated that rather than paying employees a large fixed amount per year at market rates, AEP's compensation package provides a lower fixed amount per year, and then provides employees an opportunity to earn up to the market level of compensation only if certain goals are met. This is the incentive compensation portion of the total compensation package. These goals represent a balance of the interests of the primary stakeholders any company must provide for: customers, employees, and shareholders. Parties primarily criticize the goals as benefiting both customers and shareholders, which is the basis for their cost disallowances. Such criticisms are baseless. According to Mr. Carlin, every company must balance the interests of customers, employees, and shareholders, and an incentive compensation package that supports this principle is appropriate.

Summary of the Direct Testimony of Lanny Nickell

Lanny Nickell, Vice President Engineering of Southwest Power Pool, Inc. ("SPP"), testified on behalf of Public Service Company of Oklahoma ("PSO" or "Company"). SPP is a Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas.

According to Mr. Nickell, his testimony provides information to the Oklahoma Corporation Commission ("OCC" or "Commission") describing how SPP's transmission expansion planning processes assess transmission needs and determines transmission solutions that are beneficial and necessary for the SPP region, including PSO Oklahoma retail customers. Specifically, he provided an overview of SPP transmission planning, as well as an explanation of SPP's Balanced Portfolio Projects, Priority Projects and Integrated Transmission Planning Process. His testimony also addressed cost allocation for regionally planned transmission projects. Finally, Mr. Nickell's testimony described the applicable rate schedules for SPP Transmission Service.

Mr. Nickell testified that SPP works with its members to determine the transmission infrastructure needed in the near-and long-term planning horizon to maintain electric reliability, meet public policy mandates, and provide economic benefits. SPP does not own or build transmission assets; however, its Open Access Transmission Tariff ("Tariff") contains rules that govern transmission construction by SPP members. SPP's transmission planning services include development of regional transmission expansion plans, oversight of transmission upgrade construction in accordance with approved plans, and development and implementation of cost allocation methodologies to ensure appropriate recovery by the constructing and managing utilities. SPP's transmission expansion plans are based on studies performed by SPP to determine upgrades needed to maintain reliability and provide economic benefit into the future. SPP's transmission planning processes seek to identify system limitations and needs, develop cost effective transmission solutions, and ensure timely completion of needed system expansion within reasonable cost expectations. Rather than looking at the needs of just one utility, SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefit to the region, according to one or more methods prescribed in Attachment O of the Tariff. The future projection of all transmission projects in the SPP region, as determined by these planning processes, is reported annually in the SPP Transmission Expansion Plan ("STEP"). Transmission projects contained in the STEP are the result of one or more of the following processes or sources: 1) transmission service study process; 2) generator interconnection ("GI") study process; 3) Integrated Transmission Planning ("ITP") process; 4) Balanced Portfolio process; 5) high priority study process; and 6) requests for Sponsored Upgrades.

Mr. Nickell further testified as to the evolution of SPP's Planning Processes. Historically, the transmission system was designed primarily to serve local systems. Traditional planning typically involved trade-offs between generation and transmission within a service area, and generally involved transmission needs assessments to minimally meet reliability objectives and customer needs on a utility-by-utility basis. The implementation of SPP's regional planning processes shortly after SPP was approved by FERC as an RTO in 2004 was an improvement over the local area, utility-by-utility planning that had existed previously.

Mr. Nickell testified that as part of its strategic initiative to develop a robust transmission system to benefit the SPP region, the SPP Board approved the Balanced Portfolio projects in 2009 and the Priority Projects in 2010. In 2010, SPP began its ITP process to assess the entire footprint's transmission needs over the long- and near-term.

SPP's Balanced Portfolio is the result of a strategic initiative that began in 2007 to develop a cohesive group of economic transmission upgrades that would benefit the SPP region with the costs of those upgrades to be allocated regionally. The Balanced Portfolio was approved by the SPP Board on April 28, 2009. Projects in the Balanced Portfolio included 345 kV transmission upgrades selected for the purpose of providing potential savings exceeding project costs. Attachment O to the SPP Tariff defines

"Balanced" such that for each "Zone,"[3] the sum of the benefits of the Balanced Portfolio must equal or exceed the sum of the costs. The SPP Tariff also provides that balance for the portfolio may be achieved through an adjustment or transfer of revenue requirements from the deficient Zones to the Region. The Balanced Portfolio upgrades were specifically intended to reduce existing congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades such as the Balanced Portfolio upgrades generally also provide other benefits to the power grid such as increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

At approval, SPP reported the Balanced Portfolio would provide substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio was estimated to provide an average benefit of $1.66 per month at a cost of $0.88 per month for a net benefit of $0.78 per month. The benefit-to-cost ratio ("B/C") was estimated to be approximately $1.87. SPP further reported that the Portfolio could incur a construction cost increase of up to 113%, or an increase of more than double the original estimated construction cost, and still provide a B/C of 1.0 for the SPP region. At the time the Portfolio was approved, its total construction cost was estimated at $692 million. The current status of each of the Balanced Portfolio Projects was included as Appendix 2 to Mr. Nickell's testimony.

Mr. Nickell testified on the SPP Priority Projects, which are a group of transmission expansion projects identified by SPP and SPP Stakeholders as needed to support requests for generation interconnection and long-term transmission service, address known congestion, and integrate SPP's west and east transmission systems.

Mr. Nickell explained that the Priority Projects were designed to accomplish the following objectives: Congestion reduction which is primarily achieved through APC savings and the levelization of Locational Marginal Prices ("LMPs") across the footprint; creation of additional transfer capability across the SPP footprint and relief of congestion on lower-voltage facilities for local delivery of energy, allowing additional transmission service requests to be granted; improvement of the generation interconnection process by increasing transmission capacity thereby facilitating the addition of more new generation interconnections to the grid; and increased ability to transfer power in an eastward direction by better connecting the western and eastern areas. Mr. Nickell testified that the accomplishment of these objectives provides both quantitative and qualitative benefits across the SPP footprint, including Oklahoma.

Mr. Nickell testified further that qualitative benefits of the Priority Projects were also analyzed. Some of the strategic and other qualitative benefits of EHV transmission which were difficult to quantify included: (i) enabling future markets; (ii) storm hardening; (iii) improving operating practices/maintenance schedules; (iv) reducing

[3] Zone is defined by the SPP Tariff as "the geographic area of the facilities of a Transmission Owner or a specific combination of Transmission Owners as specified in Schedules 7, 8, and 9."

reliability margins; (v) improving dynamic performance and grid stability during extreme events; and (vi) societal economic benefits. In addition, a robust EHV transmission network facilitates competitive energy markets that provide significant benefits over the long-term as market participants reposition themselves to capitalize on new opportunities arising as a result of enabling infrastructure.

Mr. Nickell's testimony explained the SPP ITP Process, which is a three-year study process that assesses long and near-term infrastructure needs of the SPP Transmission System. The intent of ITP is to bring about continued development of a cost-effective, flexible, and robust transmission network that will provide efficient, reliable access to the region's diverse generating resources.

Mr. Nickell further testified about SPP's cost allocation methodology. In June 2010, FERC approved the Highway/Byway method of sharing costs for new electric transmission required by SPP to be constructed in the SPP region. This approach, which assigns costs of high-voltage transmission regionally and lower-voltage locally,[4] will help SPP and its members build a stronger transmission grid that will benefit the entire region. The Highway/Byway cost allocation method applies to transmission expansion projects approved by the SPP Board after June 19, 2010. Highway/Byway is the result of years of incremental work by SPP's RSC. Article 7 of the SPP Bylaws explicitly extends to state regulatory agencies specific rights and authorities. The RSC has primary responsibility for determining regional proposals concerning: (i) whether and to what extent participant funding will be used for transmission enhancements; (ii) the rate structure for SPP's regional access charge (e.g., postage stamp or license plate); (iii) allocation of Financial Transmission Rights ("FTRs"), where a locational price methodology is used; and (iv) transition mechanisms to be used to ensure that existing firm Transmission Customers receive FTRs equivalent to their existing firm rights. In addition, the RSC determines the approach for resource adequacy across the entire region and, with respect to transmission planning; the RSC determines whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process.

The RSC was the key decision maker in developing and approving cost allocation mechanisms that have been used by SPP since obtaining RTO status from FERC. In 2005, in its first major effort after its formation, the RSC developed and approved the Reliability Base Plan Funding mechanism. In 2008, the RSC developed and approved an approach for much needed economic upgrades known as the Balanced Portfolio funding mechanism, used for the Balanced Portfolio Projects. Then, in 2009, the RSC continued the evolution and development of cost allocation with their leadership which led to the approval of the Highway/Byway cost allocation methodology. The Priority

[4] Under the Highway/Byway methodology, costs are shared regionally based on the voltage of the upgrade as follows: (1) the costs of facilities operating at 300 kV and above are allocated 100 percent across the SPP region on a postage stamp basis; (2) the costs of facilities operating above 100 kV and below 300 kV are allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located; and (3) the costs of facilities operating at or below 100 kV are allocated 100 percent to the zone in which the facilities are located.

Projects and all ITP upgrades are funded according to the Highway/Byway cost allocation methodology.

Mr. Nickell's testimony explained that along with the FERC approval of the Highway/Byway proposal developed by the RSC for the SPP region, FERC also approved a requirement that the impacts of the Highway/Byway be reviewed at least every three years.

In addition, Mr. Nickell provided testimony explaining the rates, terms, and conditions for Transmission Service in the SPP RTO set forth in the SPP Tariff. All rates in the SPP Tariff are approved by FERC.[5] Mr. Nickell explained that the costs associated with Transmission Service Upgrades are recovered from the cost causer in accordance with the rates, terms, and conditions set forth in the SPP Tariff. The Tariff defines the process used to identify required network upgrades and the cost allocation methodology used to assign upgrade costs to the appropriate rate schedule. Transmission Service upgrades may be directly assigned to the Transmission Customer or incorporated into the rate base depending on the jurisdictional nature of the upgrade.

Schedule 9 is one of two rate schedules associated with Network Integration Transmission Service ("NITS"). NITS allows a Network Customer to integrate, economically dispatch and regulate its current and planned designated network resources to serve its network load in a manner comparable to that in which the Transmission Owners utilize the Transmission System to serve their Native Load customers. NITS also may be used by the Network Customer to deliver energy purchases to its Network Load from non-designated resources on an as-available basis without additional transmission charges. Schedule 9 charges are based on the Network Customer's Load Ratio Share ("LRS") in the host Transmission Zone and recover the Transmission Owners' Zonal Annual Transmission Revenue Requirement ("ZATRR"). The costs allocated to a Transmission Owner's ZATRR include those costs associated with its transmission assets that are not otherwise recovered either directly from transmission customers or under Schedule 11. Included in costs recovered under Schedule 9 are the costs of those assets that were in service prior to the institution of SPP's regional planning processes and transmission upgrades constructed in accordance with planning criteria filed with FERC and utilized by a Transmission Owner that is more stringent than SPP's Criteria and NERC Reliability Standards.

Mr. Nickell testified that the charges associated with Schedules 7 and 8 apply to Point-to-Point Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery. The applicability of rates in Schedule 7 (Firm Point-to-Point) or Schedule 8 (Non-Firm Point-to-Point) rate is based on the type of service requested by the Transmission Customer. The rates associated with Schedules 7 and 8 are FERC approved Point-to-Point base rates which are a function of the Transmission Owners' ZATRRs. In situations where an SPP Transmission Service Study performed in connection with the provision of Long-Term Firm Point-To-Point Transmission Service

[5] Rates are filed with FERC pursuant to Section 205 of the Federal Power Act.

identifies a need for new facilities, costs of such new facilities exceeding the base rate are recovered from the Transmission Customer in addition to the base rate.

In addition, Mr. Nickell testified that Schedule 11 is associated with the recovery of the Annual Transmission Revenue Requirement ("ATRR") of facilities classified as Base Plan and Balanced Portfolio Upgrades, which are upgrades approved for construction by the SPP Board resulting from the ITP, high priority study, or Balanced Portfolio. The costs for Base Plan and Balanced Portfolio Upgrades are allocated to the Zone and to the Region (pursuant to Attachment H of the Tariff) in accordance with Attachments J and O, respectively, of the Tariff, resulting in a Base Plan Zonal ATRR and the Region-wide ATRR. Schedule 11 includes both a NITS and Point-to-Point component and is applied in addition to the other rate schedules associated with the applicable transmission services (i.e., Schedules 7, 8, and 9). The Schedule 11 NITS charges are applied to each Network Customer, in addition to Schedule 9 NITS described above, in proportion to the Network Customer's respective zonal or regional LRS to recover the Base Plan Upgrade's cost that each Transmission Owner has incurred. Similarly, each Point-to Point Customer will incur a Schedule 11 Point-to-Point charge in addition to the respective Schedule 7 or 8 charges.

Mr. Nickell explained that as the Transmission Provider, SPP is responsible for the administration of the rates, terms, and conditions as specified in the Tariff. With respect to Schedules 9 and 11, SPP conducts all necessary functions to properly determine the correct ATRR and billing determinates comprising the charges. SPP bills and collects for these charges and remits the money to the appropriate Transmission Owner.

<u>Summary of the Direct, Rebuttal, and Supplemental Testimonies of Jennifer L. Jackson</u>

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

Ms. Jackson testified that her testimony presented and explained the proposed PSO retail class rate design. She also presented the distribution of PSO's proposed revenue change to all retail customer classes, the updated pricing for the retail rate classes based on the proposed distribution of revenue, and the resulting revenue changes based on the updated pricing.

She sponsored the schedules and workpapers from Section M – Proof of Revenue/Rate Design and Section N - Proposed Rate Schedules of the application package.

According to Ms. Jackson, PSO's rates were updated in its last general rate case, Cause No. PUD 201000050, based on a test year ending February 28, 2010, and resulted in no overall total bill retail increase. In this filing, the test year billing units and revenues for each class reflect the changes in customer base and customer class composition since the February 2010 test year. Ms. Jackson stated that PSO was requesting a change in retail base rates of $37,720,949 million.

In addition, PSO was requesting recovery of Advanced Metering Infrastructure (AMI) costs in the amount of $7,401,819 for a total retail change of $45,122,768.

Ms. Jackson testified that the current rate structures served customers of all usage types including residential, small commercial, large commercial and small industrial, large industrial, municipal, and lighting. The rate schedules that serve the various types of customers are based on the fact that PSO is a seasonal, summer-peaking utility. 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. According to Ms. Jackson, in the current filing, PSO was proposing to continue the basic principles of its rate design and was not proposing any structural changes to its rate schedules.

Ms. Jackson testified that the revenue distribution is the rate design mechanism by which the proposed change in revenue requirement is assigned to the customer classes. The revenue distribution also determines the revenue requirement targets for each rate class in order to design rates that achieve the required revenue. The proposed cost-of-service study is the basis for the revenue distribution. However, factors other than the cost-of-service results have been taken into consideration and presented in the target base rate changes for each class.

Ms. Jackson further testified that the purpose of the equalized section of the cost-of-service study is to determine the revenue requirement necessary to move all major classes of customers to an equalized return. At an equalized return, 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 has consistently had the goal of moving classes toward an equalized return in past cases. However, moving classes to an equalized return must also be balanced with other rate design considerations such as the overall customer impact of making the move to an equalized return.

Ms. Jackson testified that PSO proposed a revenue distribution that determines a revenue requirement and rates for Service Level 1 and 2 of the Large Power and Light tariff reflecting an equalized return according to the proposed cost-of-service study presented by PSO witness John O. Aaron, based on a system average return of 7.94 percent. The remaining distribution of the revenue requirement change to achieve a system average return at 7.94 percent is proposed to be shared among all other classes.

Ms. Jackson described the proposed changes to the residential rate schedules. PSO did not propose any changes to the structure of the basic RS rate schedule. The base service charge was increased to $20.00 from the current $16.16 to account for fixed customer, meter, meter reading, and billing costs plus a portion of distribution function costs that are fixed in nature. The first-step energy rates were decreased to account for the additional movement of fixed distribution costs from the energy charge to the base service charge. The remaining kWh block rates were adjusted slightly to achieve the total class proposed revenue target. The RS class base change is proposed to be 5.93 percent, resulting in a total base plus fuel plus riders change of 4.35 percent.

According to Ms. Jackson, the LURS rate schedule is a closed rate schedule for current residential customers whose average monthly usage is limited to energy use not exceeding an average of 500 kWh or less through the on-peak season billing months of June through October. PSO was not proposing any structure changes to the LURS rate but is proposing to update the pricing of all the rate components based on the base percentage increase assigned to the residential class.

The residential class time-of-day (TOD) optional rate schedule was adjusted according to the percent change for the RS class. PSO also has two residential service tariffs that are available to gridSMART® pilot customers. PSO has a Variable Peak Pricing (VPPRS) rate schedule currently available to gridSMART® pilot customers on a voluntary basis. PSO had made the decision to remove this offering in this case.

Ms. Jackson also described the proposed commercial and small industrial service schedules. The Limited Usage General Service (LUGS) and the General Service (GS) rate schedules are available for service to small commercial customers. PSO is proposing to add a separate base service charge for LUGS customers that have single-phase metering and use less than 100 kWh per month. The base service charge and energy rates were increased by the base percentage increase assigned to the LUGS class. PSO is not proposing any changes to the GS rate structure but is proposing to adjust each rate component by the increase assigned to the GS class. The small commercial class also has optional pilot TOD rate schedules. The LUGS and GS pilot rates have been adjusted according to the corresponding LUGS and GS class percentage changes. PSO also has a Power and Light (PL) rate in the commercial class but is not proposing to change the structure of the PL rate schedule. However, the base service, energy and demand charge prices were increased by the proposed percentage increase assigned to the total PL class.

PSO also has the following commercial tariffs that are available to either particular end-use customers or to a limited number of customers: Municipal Pumping (MP), a closed tariff for municipal pumping customers, and Unmetered Service (UMS). The pricing of the MP and UMS rate schedule components has been updated based on the proposed revenue distribution. PSO is proposing to [*sic*] change the title of the UMS rate to Municipal Service (MS). This rate schedule is available to any municipally-owned lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination, and to Community Antenna Television Service (CATV) companies for power supply units. The name change still encompasses the availability of the tariff but a clause has been added to the unmetered tariff to allow PSO to install a meter on all or on at least one installation that is of the same wattage (including ballast) for each type of installation served under this schedule, where kWh usage cannot be accurately estimated.

PSO is proposing to add a new Primary Non-demand rate schedule available for customers currently taking service under rate codes 251, 255, 265, 305, 315, 353, 541 and 605 or for customers served at primary voltage but being billed on a secondary tariff prior to January 1, 2014. This proposed rate schedule is for customers who have been "grandfathered" on secondary rates due to a voltage level definition change made to the primary service designation several rate cases ago. The grandfathering has stranded these customers on secondary rate schedules due to onerous bill impacts that would be caused by migrating these customers to the LPL 3 tariff, which has a mandatory primary time-of-day rate structure with demand ratchets. The new Primary Non-Demand rate schedule provides a tariff for this group of customers that is based on a GS hours-use rate structure, with a primary voltage rate differential. PSO has moved customers currently on GS and PL grandfathered rate codes to this new schedule. The goal is to remove the grandfathered status of these customers by moving them to a primary, non-demand tariff structured to accommodate their requirements.

The Large Power and Light LPL1, LPL2, and LPL3 rate schedules serve large industrial customers taking service at transmission voltage, primary substation voltage, and primary voltage. The large industrial rate schedules have TOD rate structures designed to encourage conservation during PSO's highest-use hours, 2 p.m. to 9 p.m., during the on-peak months of June through September. PSO was also proposing to adjust the LPL 1 and LPL 2 schedule rate components, the base service charge, the per-kWh energy rate, and the peak and maximum demand charges, based upon the revenue requirement necessary to move those classes to a unity return according to the equalized section of the proposed cost-of-service study. The LPL 3 class had been assigned the same base rate increase as the residential, commercial, and lighting classes.

PSO had proposed base rate increases in the lighting rates according to the proposed revenue distribution.

Ms. Jackson stated that PSO was proposing language changes to individual tariffs, individual riders, to the Electric Service Rules, Regulations, and Conditions of Service, and to the Table of Contents. PSO has removed outdated and expired language from the tariffs and removed several tariffs that are no longer in effect, including Real Time Pricing (RTP), the Conjunctive Billing Rider associated with RTP, and the Variable Peak Pricing Residential Service Tariff that PSO proposes to discontinue. All changes, additions, and deletions are clearly marked in Section N, the proposed Tariff manual.

PSO was proposing a few changes to its Service Charges. These proposed rate changes are not to current Service Charge rates that have test year revenue associated with them. PSO does not establish new electrical connection outside of Company working hours. Therefore, PSO is proposing to eliminate the After Hours connect fee because the fee does not match the current Company practice.

PSO is proposing to remove the Radio Frequency Meter Installation Fee. This fee will be outdated due to PSO's gridSMART® initiative.

Ms. Jackson's rebuttal testimony addressed the recommendations made by various parties in the area of rate design. She addressed the following recommendations made by the following witnesses:

- American Association of Retired Persons (AARP) witness Barbara R. Alexander regarding her recommendations on Public Service Company of Oklahoma's (PSO's) proposed residential base service charge;

- Attorney General (AG) witness Edwin C. Farrar regarding the rejection of PSO's proposed rate design and residential base service charge commentary;

- Oklahoma Industrial Energy Consumers (OIEC) witness Mark E. Garrett regarding PSO's proposed revenue distribution and industrial rate design; specifically, OIEC's recommendation to reject PSO's industrial base service charges; and

- Oklahoma Corporation Commission (OCC or Commission) Public Utility Division (PUD) witness Luis F. Saenz regarding his rate design proposals.

According to Ms. Jackson, PSO's proposal, the base service charge was increased to \$20.00 from the current \$16.16 to account for fixed customer, meter, meter reading, and billing costs plus a portion of distribution function costs that are fixed in nature. In the response to data request PUD LS 01-21, PSO explained that the unit cost at equalized section of the PSO filed cost-of-service study was used to determine the appropriate level of cost to include in the residential base service charge. PSO proposed to include 100% of the distribution customer function and approximately 50% of the distribution demand function unit cost on a per-customer basis in the proposed \$20.00 base service charge. As filed, the PSO unit cost section of the cost-of-service study shows that the distribution demand function cost on a per customer basis is \$20.79. The distribution customer function includes metering, metering equipment, meter reading, billing and customer services. The unit cost section shows that the distribution customer function cost on a per customer basis is \$9.26. This cost, coupled with 50% of the distribution demand function, supported PSO's proposed base service charge of \$20.00.

Ms. Jackson further testified the minimum system study was performed as a requirement of Final Order No. 545168 from Cause No. PUD 200600285. The minimum system study was filed but was not utilized as an allocation methodology in Cause No. PUD

200800144. The Commission, having both the minimum system study and PSO's demand allocation proposal to review in the 2008 case, agreed that PSO's demand allocation for distribution function costs was reasonable. PSO's position in the 2008 case (see Moncrief testimony in Cause No. PUD 200800144) and in this case is that the distribution demand function FERC accounts are all properly classified as demand-related.

The total residential service revenue requirement is made up of all functions including generation demand, generation energy, transmission demand, distribution demand, and the distribution customer function based on the filed cost-of-service study. PSO currently has a base service charge and variable kWh rates to recover the total revenue requirement for the residential class. This introduces variability in cost recovery for a cost allocated on demand and recovered through an energy charge. In the absence of a demand-based billing unit for the residential class, PSO has proposed to assign approximately 50% of the distribution demand function cost to the fixed base service charge on a per-customer basis instead of collecting the entire functional cost for distribution on a per kWh basis.

PSO has made rate design proposals that recognize and are mindful of customer total bill impact as outlined in the rate design testimony and schedules. Also, PSO's proposed revenue distribution tempers the increase to the residential class required to achieve an equalized return as directed by the filed cost-of-service study, in recognition of customer impact.

Ms. Jackson filed Supplemental Testimony to address certain aspects of the Joint Stipulation and Settlement Agreement (Joint Stipulation) that was filed on June 17, 2014. She presented the settlement revenue distribution and the changes made to tariffs based on the provisions of the settlement and the class settlement revenue requirements. According to Ms. Jackson, the revenue distribution, rate design, and tariff revisions were the subjects of her previous direct and rebuttal testimonies in this case.

Ms. Jackson testified that Attachment A was the SPPTC tariff supported by the Joint Stipulation. Prior to the Joint Stipulation, charges billed under the SPPTC for all classes of customers, including the industrial class, were recovered on a per-kWh basis. The SPPTC tariff has been modified by the Joint Stipulation to allow demand-based billing for industrial customers taking service under the Large Power and Light 1 – 3 (LPL 1-3) rate schedules.

Attachment B was the AMI tariff supported by the Joint Stipulation. The AMI tariff was designed to recover the revenue requirement, contained in Attachment C, associated with PSO's AMI deployment and was applied on a per-meter basis. If approved, the AMI Tariff will become effective with the first billing cycle of November and remain in effect until the first base rate case subsequent to the full implementation of AMI.

As reflected in the Tariff, the total average residential class impact is $3.11 per month for the first 14 months, which is a 3.82 percent change. Because the Joint Stipulation results in no other change to PSO's overall rates, the increase from the AMI Tariff represents the overall impact on residential customers.

Attachment C portrays the allocation of the AMI revenue requirement to the rate classes receiving AMI services based on the Joint Stipulation.

Ms. Jackson further testified that Attachment D sets forth the retail revenue distribution based on the provisions of the Joint Stipulation. The revenue distribution is the rate design mechanism by which the change in revenue requirement is assigned to the classes of customers. The revenue distribution also determines the revenue requirement targets for each rate class in order to design rates that achieve the required revenue by class as proposed in the Joint Stipulation. Attachment D details the present and settlement adjusted revenues by class, the final revenue change by class, and the base and total bill impact to the customer classes including the AMI charge as contemplated by the Joint Stipulation.

The Joint Stipulation requests to remove $4.8 million of costs from base rates to be recovered through the Fuel Cost Adjustment (FA) Rider. Removing $4.8 million from base rates results in a 0.88 percent reduction to adjusted test year retail base rate revenues. Attachment D of the Joint Stipulation applies the 0.88 percent base rate reduction to all classes equally. Attachment D also depicts the base revenue change for each rate class.

Attachment D also shows the class allocation of the AMI revenue requirement associated with the AMI agreement within the Joint Stipulation, the total class fuel and rider revenues, the total proposed settlement revenues, and the total bill percentage changes by class based on the provisions of the Joint Stipulation. According to Ms. Jackson, the following table shows the major class base rate and total bill percentage changes based on the provisions of the Joint Stipulation.

Major Class	Base Rate % Change Based on Joint Stipulation	Total % Change Based on Joint Stipulation
Residential	-0.88%	3.82%
Commercial	-0.88%	0.97%
Lighting	-0.88%	0.00%
SL 3	-0.88%	0.03%
SL 2	-0.88%	0.00%
SL 1	-0.88%	0.00%
Total Retail	-0.88%	2.05%

For all classes the 0.88 percent reduction was applied to the energy rate (per-kWh rate) resulting in a reduction in the base energy charge for all classes. The class reduction to base rates through the energy charges was then added to the FA rider for recovery, increasing each class's fuel responsibility by the same amount that was removed from base rates. The Joint Stipulation proposes to increase the base service charge for the Residential Service (RS), Residential Service Time-of-Day (RS TOD), and Variable Peak Pricing (VPP) rate schedules from the current level of $16.16 to $20.

PSO currently has a base service charge and variable kWh rates to recover the total revenue requirement for the residential class. The current base service charge includes customer-related charges such as metering, meter reading, customer services and billing, but it also includes an additional amount related to the distribution demand function revenue requirement represented on a per-customer basis. The distribution demand function contains the costs for such distribution assets as poles, towers, fixtures, overhead and underground conductors, and line transformers. As part of this rate design change, the energy rates were decreased from the current per-kWh rates to account for the additional movement of fixed distribution costs from the variable energy charge to the fixed base service charge. For a typical residential customer, this rate design adjustment alone (not including the AMI tariff charge) results in no change to the base bill. The Commission has previously approved PSO's methodology of inclusion of distribution demand costs in addition to the distribution customer-related unit cost in the residential base service charge. The residential class energy rates also reflect the movement of base fuel-related costs from base rate recovery to recovery through the FA rider. The residential rate schedules are found in Attachment F to the Joint Stipulation.

Additionally, the Joint Stipulation proposes to increase the base service charge in the Limited Usage General Service (LUGS) and LUGS TOD rate schedules from $35.88 to $37.75.

Attachment E is the Standby and Supplemental Tariff supported by the Joint Stipulation. Currently, the Tariff is available on an interim basis and limited to independent power producers who were previously taking service under PSO's Real Time Pricing Tariff. The Joint Stipulation recommends that this tariff be made available on a permanent basis to any qualifying customer.

Attachment F contains the rate schedules for the residential and the LUGS rate classes that have changes to the base service charge. The residential service tariff sheets also include language stating that home energy reports are available upon request for any customers with AMI meters. The tariff sheets included in Attachment F include the Low Use Residential Service (LURS), RS, RS TOD, VPP, LUGS, and LUGS TOD.

The Stipulating Parties agree that PSO's base rates approved in this cause will reflect the removal of the 3.4 cents per kWh of embedded fuel currently included in the energy rates of every rate class.

Summary of the Direct and Rebuttal Testimonies of Steven R. Bertheau

Steven R. Bertheau, Senior Vice President, and Project Director with Sargent & Lundy^{LLC} (S&L), testified on behalf of Public Service Company of Oklahoma (PSO).

Mr. Bertheau'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 SRB-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. Bertheau, S&L had prepared over 260 demolition cost estimate studies on 77 power plants while exclusively serving the power plant industry for more than 123 years. 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 as [*sic*] the maintenance or upgrading of power plant configurations for a variety of plant changes. Mr. Bertheau 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. Bertheau 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 single new generation power plant design project and every single power plant retrofit project that has been performed by S&L throughout its 123-year history has involved [*sic*] 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 the previous demolition estimates prepared by S&L is provided in EXHIBIT SRB-2.

Mr. Bertheau 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 good 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. 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/or potential public safety risks.

In some cases, removal and disposal of asbestos or other potentially hazardous materials may also be required.

Mr. Bertheau 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 2008 by S&L. The purpose of this update was to capture any changes that may have occurred at the PSO facilities between 2008 to 2013. S&L's method of updating these cost estimate studies started with participating in a kickoff meeting with representatives of PSO in order 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. 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.

Mr. Bertheau testified that back in our offices, we reviewed this data in more detail and finalized the scope of the cost estimates and the assumptions that were used to develop the cost estimates. For example, in many instances, we assumed that there was sufficient room on site to dispose of all the non-hazardous debris. We assumed that it would not be necessary to remove the tens of thousands of feet of underground piping and wiring from the sites. In my opinion, assumptions such as these minimize the dismantling cost estimate and result in a very conservative and reasonable cost estimate for dismantling the facility.

To confirm certain information and to gather more data, site visits were then conducted in July 2013. We talked with the plant personnel, who answered our questions and presented us with additional information. Our cost estimates were updated considering the data I have described above in accordance with S&L's Quality Assurance Program and then they were reviewed with PSO personnel. PSO comments were incorporated, as appropriate, into the documents and the final cost estimates were subsequently issued for use. These cost estimates were included in his testimony as EXHIBIT SRB-3.

According to Mr. Bertheau, the assumptions used to prepare these estimates were consistent with prudent industry practices and previous S&L demolition estimates. S&L's experience with demolishing parts of existing facilities to modify plant configurations for accommodating new equipment also provided a basis for the estimating procedures used to prepare the demolition cost estimate studies for PSO.

Mr. Bertheau filed rebuttal testimony to address and respond to certain statements made in the direct testimonies of OIEC witness Jacob Pous and (PUD) witness Carolyn Weber in regards to PSO's "Conceptual Demolition Cost Estimate" studies prepared by S&L and attached to his direct testimony as Exhibit SRB-3. In particular, according to Mr. Bertheau, Mr. Pous questioned the methodologies and the assumptions employed in the studies regarding productivity of resources, labor rates, materials levels, quantities of scrap materials, pond inclusion, and scrap valuation. In their testimonies, both Mr. Pous and Ms. Weber challenged the cost contingency included in the S&L studies and questioned the cost estimates resulting from these studies. Mr. Pous also contended that differences between the studies performed for this proceeding and the studies in PSO's prior base rate case Cause No. PUD 201000050, somehow render the results of the studies in this case unreliable.

Mr. Bertheau testified that Mr. Pous' criticisms of S&L's studies were invalid and should be rejected as is further explained and demonstrated in detail in his testimony. In addition, maintaining a positive contingency in the S&L studies is necessary to develop a meaningful cost estimate for demolition. The contention that differences between the studies in this case and the studies in Cause No. PUD 201000050 means that the studies in this case are unreliable is not correct and should be rejected. His statements are not based on any analysis of the reasons for the differences and lacked merit.

It was Mr. Bertheau's initial overall observation that 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. Instead, he took a scattergun approach of criticizing 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 Exhibit SRB-3 did consider the costs of demolition. These studies are complete engineering studies of what costs will be expected to be incurred to dismantle and remove each PSO generating plant at its retirement. And in contrast to Mr. Pous' scattergun approach, which simply takes issue with selected elements of the S&L studies, he believed appropriate consideration should be given to the overall merit of the studies, how they were conducted, and the engineering experience of S&L underlying the studies. In doing so, one will find that the S&L studies represent a reasonable and reliable projection of the costs of dismantling and removing PSO's generating facilities upon their retirement.

According to Mr. Bertheau, Mr. Pous has made similar arguments to other demolition studies in other regulatory commissions.

Mr. Pous employed the same tactic of asking overly broad and vague questions in other jurisdictions and then selects elements of the demolition study to try to develop issues with. Recently, he employed this similar tactic, raising similar issues in the most recent base rate case for PSO's sister company, Southwestern Electric Power Company (SWEPCO). The ALJ, and subsequently the Public Utility Commission of Texas, found that these arguments of Mr. Pous were [*sic*] unfounded and lacked merit.

> *"The plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment."*[6]

Mr. Bertheau further testified that a decommissioned plant can present public safety issues if not properly closed and dismantled. An electric utility's first priority is safety, not only for its employees, but for the general public as well. The purpose of the S&L demolition cost estimate study was to identify the necessary scope and cost to demolish a plant while addressing the required activity needed to safely and prudently dismantle the facility in a cost effective manner. Company witness Spanos explains why a reasonable estimate of the costs to remove depreciable plant at the end of its useful life is important to the conduct of a depreciation study.

III. Statements of Position

AARP STATEMENT OF POSITION

COMES NOW AARP, by and through its undersigned counsel, and hereby files the following Statement of Position.

1. RETURN ON EQUITY – Between 9.19 and 9.50% ROE

AARP supports the range of return on equity (ROE) as set forth in the responsive testimony filings in this case on April 23, 2014 of the Attorney General (AG), the PUD Staff (Staff) and the Oklahoma Industrial Energy Consumers/Wal-Mart Stores East, LP and Sam's East, Inc. (OIEC) (Wal-Mart). The AG advocates the adoption of 9.19% ROE.[7] The Staff's calculation of appropriate ROE is 9.50%.[8] And finally, the OIEC supports an ROE of 9.25%.[9] Based on the testimony supplied by these witnesses of the calculations of ROE and the evidence provided to support ROE calculations, AARP believes an ROE in the range of 9.19% to 9.50%, but in no event higher than 9.50%, is an appropriate ROE in this matter.

2. OFF SYSTEM SALES - 100% net gains to ratepayers

With the various parties' support of the elimination of OSSE rider, both Staff and OIEC recommend that gains made from off system sales into the SPP day-ahead market should flow in

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[6] SOAH Docket No. 473-12-7519 Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs, Findings of Fact, No. 193. Pg. 333.
[7] Responsive Testimony of Edwin Farrar, April 23, 2014, p. 7.
[8] Responsive Testimony of Michael Knapp, April 23, 2014, p 33, ll. 18-19.
[9] Responsive Testimony of David Parcell, April 23, 2014, pp. 2-3.

full (100%) to customers through the fuel adjustment clause.[10] AARP agrees that the new SPP day-ahead market provides a market place for such transactions; therefore there is no longer a basis to provide a portion of benefits to PSO shareholders to seek out and create opportunities for power sales. This would also make such treatment for customers in Oklahoma consistent across PSO and OG&E territories.

3. DEPRECIATION RATE CHANGES - Reject PSO's Newly Developed Depreciation Rates

PSO has proposed radically different depreciation rates for all of its asset classes by modifying asset lives and salvage value calculations.[11] PSO's new depreciation rates result in an increase in revenue requirement of about $30 million.[12] The Attorney General also agrees with the rejection of PSO's requested depreciation changes.[13] AARP supports the accounting adjustments made by Staff and OIEC which reverse PSO's application of its new (and highly questionable) depreciation rate changes.[14]

4. INCENTIVE COMPENSATION – Adopt Staff, AG and OIEC traditional OCC treatment

AARP supports the traditional treatment of incentive compensation in rates as seen in prior utility rate cases in Oklahoma. Moreover, PSO did not provide any evidence to support any deviation from normal treatment of these expenses or provide any information that would warrant a major reconsideration of such accounting treatment by the Commission. Staff, the Attorney General and OIEC support traditional and historic treatment of employee incentives, which means 50% of short-term and 100% of long-term employee incentive compensation, are excluded from rate base.[15]

PSO also has a long-term stock incentive plan and a Supplemental Executive Retirement Plan (SERP), both of which are typically not included in a utility's rate base. Various parties have reversed PSO's inclusion of such costs in rate base.[16] AARP supports the accounting adjustments necessary to back out 50% of short term employee incentives and 100% of long-term incentive and executive stock compensation.

5. STAFF'S RATE DESIGN AND IMPACT ON RESIDENTIAL CUSTOMERS – Reject Staff's shift of cost allocation to residential customers

In responsive testimony on rate design filed May 7, 2014, Staff witness Mr. Luis Saenz

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[10] Responsive Testimony of Sharon Fisher, April 23, 2014, p 11 and Responsive Testimony of Mark Garrett, May 7, 2014, pp. 42-43.
[11] For a full analysis of this issue see the Direct [sic] Testimony of Jacob Pous, April 23, 2014.
[12] Direct [sic] Testimony of Jacob Pous, April 23, 2014, p. 2, l. 28.
[13] Responsive Testimony of Edwin Farrar, May 7, 2014, p. 4, ll. 16-17.
[14] Responsive Testimony of Mark Garrett, April 23, 2014, pp. 55-56.
[15] Responsive Testimony of Mark Garrett, April 23, 2014, p 20, 21-48, Responsive Testimony of Javad Seyedoff, April 23, 2014, pp. 12-14 and Responsive Testimony of Edwin Farrar, April 23, 2014, p.11-14.
[16] Responsive Testimony of Mark Garrett, April 23, 2014, pp. 20, 43 and 48

takes issue with how PSO distributed its requested rate increase across customer classes.[17] Mr. Saenz takes Staff's recommended rate increase of $2.9 million and for the rate design allocation, recommends the residential class actually receive an increase in rates of $6.4 million while spreading various rate decreases among other customer classes (except C&I SL2).[18] He supports this shift in additional costs to the residential customers by arguing his objective is to move the various classes closer to a full rate of return by class. He states that he is seeking to move classes closer to parity,[19] but acknowledges this should be done gradually.[20]

AARP does not agree that an appropriate and fair rate design would have one class shoulder an increase that is twice the size of the overall rate increase proposed by Staff.[21] There is a common principle applied to rate design in other jurisdictions which says that no customer class should ever receive a rate increase if another class is simultaneously receiving an overall decrease in its rates. In other words, other classes might get down to a zero change, but the shifting of costs onto the residential class should stop at that point and go no further. Parties must recognize that determining the rate of return by class relies on a cost of service study which requires many subjective allocation decisions and is, like ratemaking itself, an art and not a science.

AARP understands that Staff is attempting to reflect somewhat conflicting goals when determining how to reallocate rates among customers. At a minimum, AARP supports an equitable rate design that limits customer class rate reductions in any year that an overall rate increase is advocated. This approach is commonly used as a guiding principle in other states and lessens the rate shock experienced by those rate classes that are expected to take on higher rates and also provides for "gradual" change in costs between rate classes which is an important characteristic acknowledged by Staff.

AARP's failure to comment all a variety of accounting adjustments presented by the parties in this case should not be taken an objection or support for any specific adjustments. AARP reserves the right to cross examine witnesses and raise issues necessary to protect its interests in this matter.

LATE FILED STATEMENT OF POSITION OF QUALITY OF SERVICE COALITION

COMES NOW, Quality of Service Coalition ("Coalition"), after consultation with all parties who have expressed no objection, submitting this Late Filed Statement of Position in response to the Application of Public Service Company of Oklahoma ("PSO") to be in compliance with Order No. 591185 issued in Cause No. PUD 201100106 which requires a base rate case to be filed by PSO and the resulting adjustment in its rates and charges and terms and

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[17] Responsive Testimony of Mr. Luis Saenz, May 7, 2014, p. 23. Staff also corrected its revenue requirement calculation from a reduction in rates of $7.2M to an annual increase of $2.9M See Responsive Testimony of Robert Thompson, May 7, 2014, pp.3-4.
[18] Responsive Testimony of Mr. Luis Saenz, May 7, 2014, p. 21.
[19] Responsive Testimony of Mr. Luis Saenz, May 7, 2014, p. 22.
[20] Responsive Testimony of Mr. Luis Saenz, May 7, 2014, p. 11.
[21] At the same time, Staff's proposed rate design moves another rate class (Lighting) actually further away from full class cost of service return.

conditions of service for electric service in the state of Oklahoma. Coalition's attorney experienced a computer failure and was unable to recover [*sic*] the document prepared for filing on May 12, 2014. This late filed Statement of Position is submitted to respond to the Procedural Schedule requiring filing [*sic*] on the above date.

Coalition and its members, including individual residential customers, commercial customers, trade associations, and cities and towns in Oklahoma are concerned with the issues in this case because of the potential impact of adjustments that would result from the requests made by PSO. PSO's testimony and the testimony already filed by other interveners include issues related to PSO's issues, including but not limited to, requested rate of return, changes in fuel adjustment clause, numerous rider recovery provisions, installation of gridSmart meters, treatment of purchased power, and other issues which will be the subject of hearings scheduled in this matter.

Coalition will not present a witness during the hearings on the merits, but Coalition 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 cause should circumstances change or information not previously known becomes available in the course of conduct of this proceeding.

IV. Findings of Fact and Conclusions of Law

The Order Regarding Procedural Schedule Order No. 622061 (Order No. 627830) governed the hearing. Order No. 627830 granted the parties' request that a single hearing be held to address the reasonableness of the Joint Stipulation and the contested issues. (Order No. 627830, p. 3.) The ALJ's findings are organized as contested issues and the reasonableness of both the first and second Joint Stipulations (Joint Stipulation 1 and Joint Stipulation 2). Recommendations are made after a discussion of the issues and findings.

Based upon the ALJ's review and evaluation of the pleadings, testimony of witnesses, the first and second Joint Stipulations and evidence contained in the record for this Cause, and upon a full and final consideration thereof of the entire record and hearing on the merits, the ALJ makes the following findings:

A. Jurisdiction

PSO is an Oklahoma corporation authorized to do business in the State of Oklahoma. The Commission finds that PSO is a public utility with plant, property, and other assets dedicated to generation, transmission, distribution, and sale of electric power and energy within the State of Oklahoma. This Commission has jurisdiction over this cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma and 17 O.S. §§151, *et seq*.

B. Notice

The ALJ finds that PSO is in compliance with Order No. 624719 and the requirements of OAC 165:5-7-51.

C. Test Year

The test year in this Cause is a twelve month period ending July 31, 2013. The six-month post test year period for pro forma adjustments pursuant to 17 O.S. § 284 ends January 31, 2014.

D. Contested Issues

(1) Deployment of AMI and recovery of costs through a rider (Alexander Responsive, p. 8 LL 5-6.);

(2) Placing Distribution Automation and Volt/Var capital costs in rate base (Alexander Responsive, p. 8 LL 13.);

(3) PSO should be required to follow all disconnection rules for customers with AMI meters (Alexander Responsive, p. 8, LL 16-19.);

(4) General rejection of riders (Alexander Responsive p. 9, LL 1-3.);

(5) Opposed increase in residential base service charge (Alexander Responsive p. 9, LL 4-6.);

(6) PSO should have a low income bill payment assistance program similar to that of OG&E (Alexander Responsive, p. 9 LL 7-9.);

(7) The Commission should undertake an audit or "other focused examination" of the expenditures being recovered for vegetation management currently being collected in the System Reliability Rider (SRR) and base rates (Alexander Rebuttal, p. 4, LL 8-11.); and

(8) Approval of the Joint Stipulation and Settlement Agreements. (Tr. 7-21, sd 191, LL 9-12.)

E. Review and Findings Regarding Contested Issues

(1) Deployment of AMI and recovery of costs through a rider.

I. Introduction

Ms. Alexander recommends rejection of PSO's proposal to deploy AMI throughout its service territory and to recover the costs through a rider because she asserts that PSO's cost benefit analysis does not show the program will be cost beneficial to customers and the proposals of the consumer programs are not designed based on the pilot characteristics. (Alexander Responsive, p. 8, LL 5-11.)

As explained below, PSO presented evidence that the cost benefit of the AMI deployment is positive, though Ms. Alexander disagreed with most of PSO's assumptions. However, PSO maintained that it was not just the cost benefit analysis that drove its decision to deploy AMI technology throughout its territory. PSO Witness David Sartin explained, "It's really not just about the cost-benefit analysis, although the cost-benefit analysis does show over the fifteen-year period that these meters are expected to be in service that it's a cost savings for customers." (Tr. 7-21, sd 50, line 24 to sd 51, line 2.)

Mr. Sartin explained that it actually is about a "push" for customers on a cost benefit basis, but:

> You know, it shows a little bit of a net present value over a fifteen-year period, but through the operation of the AMI tariffs customers actually have opportunities to lower their bills, and they also have opportunities to take actions that lower their needs during the time that our costs are highest and reduce the capacity that we have to have in generating plants. And so, that not only benefits that individual customer, that benefits every other customer, as – as well. (Tr. 7-21, sd 65, LL 1-12.)

Other parties indicated as well that it was not just the cost benefit analysis that led each to support the Joint Stipulation including PSO's proposed AMI deployment. AG Witness Farrar stated: "There are other benefits than economic, as I just mentioned. Participation in demand -- effective demand side management programs and so forth, outage tracking that can save lives, not to mention inconvenience." (Tr. 7-21, sd 160, line 25 to sd 161, line 4.)

PUD Witness Thompson testified:

> "There are a lot of benefits . . . [that] . . . help the consumers. They can manage their electric usage. When the consumer has managed electric usage, it helps the company and hopefully shave on their peak demand, which would help with building a generating facility, so it helps with truck rolls, it helps with turning on the meter when somebody wants service, it helps the company with turning off meters when there's a need for that. There's a lot of benefits to having an AMI program." (Tr. 7-21, sd 145, LL 7-16.)

Counsel for OIEC stated that "some of our members will bear the costs of these Smart Meters. But, notwithstanding that, we have heard testimony today about benefits, and both quantitative and qualitative, so we support the roll out of the Smart Meters." (Tr. 7-22, lw 104, LL 20-25.)

Counsel for QSC stated:

> [O]ne of my members is the City of Owasso where a pilot project was located. They are already seeing benefits from the installation of the AMI process there. We think those will be duplicated in other communities. We think individual citizens have and individual customers have the opportunity to utilize the AMI process by installing thermostats, by using the energy reports that are provided, by using the website to better manage their individual usage. And for that reason we think it has benefit to our various members and both businesses and individuals. (Tr. 7-22, lw 106, LL 4-15.)

Notwithstanding PSO's and other parties' reliance on quantitative and qualitative benefits, Ms. Alexander focused most of her attention on the quantitative benefits discounting the value of any qualitative benefits as explained below.

II. <u>Cost Benefit Analysis</u>

With respect to the cost benefit analysis, Ms. Alexander took issue with, among other things, the cost of the installation of the AMI meters; the cost and benefits of a future Pre-Pay billing program; the rebate costs associated with in-home thermostats; savings from avoidance of bad debt and theft; savings from call center efficiencies; savings from avoided capacity additions; whether there was sufficient data from PSO's pilot deployment to justify a broader deployment; and the value of qualitative benefits of AMI deployment in addition to her broader dispute over use of a rider to recover AMI deployment costs.

Ms. Alexander admitted that in each of the 18 cases in which she testified regarding AMI, she "opposed the deployment of AMI based on her analysis of the distribution [*sic*] company's proposed costs and benefit analysis on the grounds that ratepayers would bear all the risk that the identified benefits would occur as predicted and/or that the assumptions that lead to the predicted benefits were faulty" and that she was criticizing PSO for the same reasons. (Tr. 7-22, lw 7, LL 8-14; HE 8, AARP's Response to PSO's Date Request 3-11.) Ms. Alexander envisions her role as an intervenor to focus on "holes" in programs (Tr. 7-21, sd 218, LL 14-17.) However, it is PSO's duty to establish whether in totality, PSO's request for cost recovery is reasonable as supported by the facts and evidence, not free of any of the "holes" that Ms. Alexander admittedly invariably finds with all such programs that she reviews. PSO is not requesting a final finding of prudence or reasonableness of the deployment and costs until a future proceeding. (Sartin Supplemental Rebuttal [Supp. Rebut.] p. 5, LL 20-21, p. 6, LL 7-11, p. 7, LL 7-8, 20-23, Tr. 7-21, sd 48, line 21 to sd 49, line 3.)

Regarding the cost benefit analysis, Mr. Lewellen testified that the program gave a positive net present value of $3.5 million (Lewellen Supp. Rebut. p. 8, LL 1-5), and Ms. Alexander herself acknowledges a positive cost benefit ratio over the 15 year life of the AMI meters. (Alexander Supp. Resp. p. 3, LL 3-10.) Ms. Alexander also conceded that PSO has "some modest ability to achieve some of those programs as PSO has outlined in its proposal" (Tr. 7-21, sd 193, LL 5-6.) However Ms. Alexander, consistent with her perceived role to highlight "holes" rather than look at the totality of the case, emphasizes the risks that PSO's assumptions and estimates may be incorrect and argues that shareholders should bear the risk that the benefits will actually be capable of being delivered in the manner and amount described. (Alexander Supp. Resp. at p. 6 LL 11-13, 16-19.) In fact, Ms. Alexander admitted that her invariable disagreement with cost recovery proposals for AMI is based on her "problem" with "extended costs involved in installing this system" and her invariable dissatisfaction with the evidence of benefits beyond "reduced operational costs which inure to the benefit of the utility and the shareholders in between rate cases." (Tr. 7-21, sd 232, LL 20-25.)

As a general matter, the ALJ notes that PSO does bear the risk that the benefits will be delivered in that, as pointed out above by Mr. Sartin, PSO's deployment will be subject to Commission review, and the Commission can then determine whether PSO deployed the program prudently and whether the program is yielding benefits and determine whether to finally authorize PSO to obtain full cost recovery of the program. The ALJ also notes that the "reduced operational costs" that Ms. Alexander alleges only inure to the benefit of the utility are being guaranteed by PSO in the amount of $11 million over the first four years of the rider. (Lewellen Rebuttal p. 6, line 3-10.) See also page 7, lines 4-20 of Lewellen's Rebuttal Testimony wherein he explains why these guaranteed savings are comparable to those guaranteed by OG&E in Cause No. PUD 201000029. PUD Witness Robert Thompson also indicated that ". . . when these costs are rolled into rate base, whatever savings PSO incur -- or captures will roll to -- roll through to the consumers. So, we are not limited to the six. It's whatever actually happens when we have a rate proceeding." (Tr. 7-21, sd 118, LL 2-6.)

A. <u>Cost of AMI Meter Installation</u>

With regard to PSO's cost benefit analysis and the supporting calculations, Ms. Alexander takes issue with PSO's calculation of the costs of the installation of the AMI meters. (Alexander Supp. Resp. p. 7, LL 15-21.) But Mr. Lewellen points out that PSO based its costs on PSO's earlier deployment and initial vendor pricing information based on the buying power of AEP. He explained that PSO is currently in the competitive bidding process and it is confirming PSO's cost estimates. (Lewellen Supp. Rebut., p. 5, LL 10-19.) He elaborated that PSO is competitively bidding all aspects of the project, for example, the AMI network that PSO used in a pilot versus what AEP operating companies in Texas used. "We have experience with both of those systems. So we're competitively bidding all aspects, including the meters, the network, and from a web portal to everything will be competitively bid to get the best possible price" and that the indicative pricing PSO was getting back from vendors was "holding true" to its forecasts. (Tr. 7-22, lw 46, LL. 12-25.)

Mr. Lewellen stated that "we identified from our pilot programs initial vendor pricing, but also leveraging AEP's buying power of the things that we can get as far as when we're looking at a utility of five million going out for pricing versus somebody of a hundred thousand we can get better pricing, and also the experience of the roll-outs at other AEP operating companies in Ohio and Texas of their costs, plus our experience being the utility business of understanding costs, of -- of forecasting what those would be." (Tr. 7-21, sd 100, LL 9-20.) Accordingly, the estimates were informed by initial vendor pricing from the pilot, the buying power of AEP, the experience of other operating companies, and the company's long history and experience in forecasting costs.

PSO supported its AMI cost estimates and efforts to provide the lowest cost reasonably possible to its consumers.

Ms. Alexander also argued that the Company's bill impact estimates and NPV analysis did not include the estimated $64.7 million of stranded costs associated with existing meters replaced by AMI meters. (Alexander Supp. Resp. p. 5, LL 11-13.) The ALJ credits the testimony of Mr. Sartin in this regard. Mr. Sartin explained that there was no customer bill impact regarding recovery of the costs of existing meters as PSO will continue to recover the costs of existing meters through base rates, and base rates would not change under the Joint Stipulation. (Sartin Supp. Rebut. p. 11, LL 12-14.) He further testified that the costs were not included in the NPV analysis:

> [B]ecause only the incremental costs and benefits are included in such calculations, and that sunk costs, like existing meters, are specifically and appropriately excluded. For financial-based decision-making tools like net present value analyses, the inputs are only the changing costs and benefits because companies have no ability to impact the costs and benefits of prior events. PSO incurred the investment in the existing meters to provide service to its customers, and such costs continue to be appropriately recoverable from customers. This was also permitted in the OG&E case referenced above. (Sartin Supp. Rebut. p. 11, line 15 to p. 12, line 3.)

B. <u>Pre-Pay Billing Program</u>

Ms. Alexander also questioned the Company's calculations regarding the costs of and benefits from a future Pre-pay program. (Alexander Supp. Resp. p. 8, line 6 to p. 9, line 10; p. 21, line 17 to p. 23, line 8, Tr. 7-21, sd 219, line 19 to sd 223, line 12.) Ms. Alexander was dissatisfied with PSO's justification of its estimate of $2.1 million of capital costs to be incurred to implement the Pre-pay program and PSO's inclusion of the costs of education for a future Pre-pay program with the costs of educating customers about the overall AMI deployment. (Alexander Supp. Resp. p. 8, line 11, to p. 9, line 10.) She also seems to decide what features PSO's future Pre-Pay program will have and what customer protections she believes will be lost (Tr. 7-21, sd 220, LL 4-5.), despite asserting that she has no idea what the program will look like. (Alexander Supp Resp. p. 23, LL 1-3; Tr. 7-21, sd 196 LL 6-8.)

Mr. Lewellen reiterated multiple times that the Pre-pay program would be a voluntary billing program for which PSO would seek approval. (See, e.g., Lewellen Rebut. p. 14, LL 7-11;

TR. 7-22, lw 40, LL 14-19.) Mr. Lewellen explained that the $2.1 million in capital is for IT infrastructure to implement a pre-pay program and that the costs are identified in an extensive workpaper of Company Witness Andrew Williamson. (Lewellen Supp. Rebut. p. 6, LL. 4-16.) Mr. Lewellen explained that the only O&M costs anticipated were for Pre-pay education which are associated with the overall AMI education efforts including letters, newspaper ads, and door hangers. (Lewellen Supp. Rebut. p. 6, line 17 to p. 7, line 2.)

As Mr. Lewellen explained about the future pre-pay program:

> As we looked at prepay a couple years ago and -- in the pilot area, and it was very-- very expensive to deploy a prepay program in -- in a pilot program because of the IT system. So, we had initial cost estimates as to what it would take to do that, and we have included those costs within this proposal and also identifying that the details we're going to be coming back later with what the program details would look like back to the Commission for approval on that. (Tr. 7-21, sd 100, Line 23 to sd 101, Line 6.)

As Mr. Lewellen stated, "And again, we're going to be designing the program, we're going to be submitting it for approval to the Commission later this year. So we're still working through those details." (Tr. 7-22, lw 40, LL 16-19.) Regarding forecasting participation rates, Mr. Lewellen expressed confidence that those participation rates are "realistic and attainable" based on the experience of other utilities, since, as he explained above a pilot was cost prohibitive because of the IT infrastructure costs. (Tr. 7-22, lw 51, Line 24 to lw 52, Line 7.) The ALJ agrees with Mr. Lewellen's conclusion that pre-pay programs are voluntary programs that have been "seen across the industry with the deployments of AMI in other industries that it is a prevailing approach. It is another customer choice and an option for . . . customers." (Tr. 7-22, lw 52, LL 13-16, 21-24.) The ALJ also credits PSO's explanations regarding the cost of implementation of and education about the proposed Pre-Pay program and its benefits.

C. Thermostat Rebate

Ms. Alexander asserted that PSO did not include rebate costs associated with thermostats past the first two years of the program. (Alexander Supp. Resp. p. 9, line 19 to p. 10, line 1; Tr. 7-21, sd 196, LL 14-18.) This was despite PSO's repeated indication that it did include such costs for the full 15 years of forecasted program costs, reflecting a reasonable drop off in program enrollments in later years. Mr. Lewellen explained that PSO "forecasted 30,000 participants over the first five years. And in year six we dropped off, a conservative approach, and said we had about 2,000 enrollments. So we forecasted those costs out." (Lewellen Supp. Rebut. p. 7, LL 5-12; Tr. 7-22, lw 53, LL 13-20.)

Ms. Alexander disagreed with the Company's decision to offer a rebate for thermostats for customers who participate in its consumer programs suggesting it will result in lower participation rates for its consumer programs. (Alexander Supp. Resp. at p. 20, line 17, to p. 21, line 13; Tr. 7-21, sd 196, LL 19-23.) PSO reiterated that it did not believe the rebate will discourage customer participation, that the rebate may not necessarily be a post-purchase rebate, and that PSO anticipates it will cover the cost of the device. (Lewellen Supp. Rebut. p. 16, LL 12-21.) Ms. Alexander bases her arguments of the effect of the rebate solely on her surmise. PSO based its estimates of customer participation, in part, on its experience with its energy efficiency and demand programs. Mr. Lewellen testified "that customers are much more likely to fully utilize energy efficiency programs when they are engaged in the programs by taking some action on their own behalf and/or having invested some of their own funds" and that this is the predominate approach used by utilities around the country. (Lewellen Supp. Rebut. p. 17, LL 1-8 & LL 11-12; Tr. 7-22, lw 42, LL 3-22.)

He explained that one of the things PSO learned from the pilot is that it wanted to offer commercially-available devices. (Tr. 7-22, lw 42, LL 4-8.) The devices used during the pilot were not commercially available and had to be purchased and installed by utilities. (Tr. 7-22, lw 54, LL 2-7.) Since that time relatively easy to install, off-the shelf devices have become available at retail. (Tr. 7-22, lw 54, LL 7-8; Lewellen Supp. Rebut. p. 8, LL 11-17.) And many other utilities seem to have made a similar decision as it is the prevailing approach throughout the industry. (Tr. 7-22, lw 42, LL 4-8; Lewellen Rebut. p. 10, LL 1-7; Lewellen Supp. Rebut. p. 17, LL 11-12.) It is also important to note that the in-home device is only necessary for the Direct Load Control, not the Variable Peak Pricing Residential Service or Time of Day programs. (Lewellen Supp. Rebut. p. 16, lines 10-11.)

It is for these reasons that the ALJ finds that PSO's decision to offer a rebate towards thermostats is reasonable and accepts PSO's assertion that it does not affect PSO's estimates of participation rates in its consumer programs.

D. <u>Reduction in Theft</u>

Ms. Alexander acknowledges the validity of the Company's estimated benefits for avoided field labor and fleet costs, consumption on inactive meters, and obsolete meters avoidance but she does not credit the Company's estimates of savings with respect to avoidance of bad debt or theft and call center efficiencies. (See Alexander Supp. Resp. at p. 11-16.) First, Ms. Alexander seems to confuse bad debt with theft. (Tr. 7-21, sd 225 LL 13-25 to sd 226, LL 1-17.) With respect to theft reduction, Ms. Alexander stated, "There is no dispute that when the meter is tampered in the AMI system that an alert is set off and the company will be notified that somebody has tried to tamper with the meter. . . . There is a benefit to that alert and that notification and that determination that an investigation needs to occur." (Tr. 7-21, sd 225; LL 17-24.) Then she inconsistently argues there is no evidence that "AMI systems could or would actually result in higher levels of theft detection" (Alexander Supp. Resp. p. 13, LL 12-14) or "what AMI systems actually do to detect theft and reduce bad debt." (Tr. 7-21, sd 226; LL 13-16.)

Mr. Lewellen, who has an Electrical Engineering degree and 24 years of electric utility operations experience (Lewellen Direct, p. 3, LL 9-19), explained, "Until you actually can identify theft, you don't know it is occurring. . . . [W]e actually have to go visually see a theft occurring. We have to see somebody's diverting the meter or seeing something that is wrong. But with an AMI with the data that is coming back or the alarms, we're able to gather more information, do analytics and identify those theft where they may be occurring and allow us to investigate more locations." (Tr. 7-22, lw 47 LL 18-25.) "So it is identifying the theft that is the challenge." (Tr. 7-22, lw 66, LL 17-18.) PSO's internal data can track identified theft (Lewellen Supp. Rebut. p. 11, line 19), which PSO does not know about until visually seeing evidence of it (by one of its 111 field personnel responsible for 554,000 meters, *see* (Lewellen Rebuttal, p. 6, LL 13-14, p. 7, l. 9), but AMI functionality will identify more theft than can be detected manually. Accordingly, internal data is not sufficient for estimating the benefits of theft avoidance, and that is why PSO relied on industry benchmarking, a widely used practice, as evidenced by OG&E's use of the same metric in Cause No. PUD 201000029. (Lewellen Supp. Rebut. p. 12, LL 6-22, and p. 13, LL 1-9.)

E. <u>Reduction of Bad Debt</u>

Initially, Ms. Alexander erroneously attributed most of the savings from bad debt expense to the prepay program. This misunderstanding comprised the bulk of her written testimony, which she corrected at the hearing. (Cf. Tr. 7-21, sd 186, LL 7-13 and Alexander Supp. Resp. p. 14, LL 8-20, and p. 15 LL 1-20.) Then she testified that PSO valued the benefit at $16 million rather than $13.8 million that PSO actually estimated. (Cf. Tr. 7-21, sd 209, LL 21-22 and Lewellen Supp. Rebut. p. 13, LL 14-15.) Ultimately, she maintained her objection (again, associating it with theft avoidance, *supra*) to PSO's bad debt reduction estimate because of the use of industry benchmarking. Mr. Lewellen pointed out why benchmarking was appropriate and explained that the pilot area was too small to use PSO's internal data for estimating the reduction in bad debt expense from AMI. (Tr. 7-22, lw 65, LL 3-12.)

F. <u>Call Center Efficiencies</u>

Ms. Alexander based her objections to PSO's call center efficiencies on some unsupported assumptions. Mr. Lewellen rebutted Ms. Alexander's unsupported assumption that having increased information available to customers will increase customer calls, explaining that the exact opposite is true because of the better and more accurate data concerning usage and billing. (Lewellen Supp. Rebut. p. 14, LL 15-22.) This more accurate data that will result in fewer customer calls includes the following listed as qualitative benefits challenged by Ms. Alexander: fewer estimates (which often result in complaints) and more actual readings, customers' ability to see forecasted bills, which allows proactive changes rather than after-the-fact bill reactions, and the ability to track usage against prior periods with a temperature overlay. (Cf. Lewellen Supp. Rebut. p. 20, LL 7-23 and Alexander Supp. Resp. p. 28, LL 8-18.) Ms. Alexander has no support for her assertion that call center activity will increase, while PSO's assumptions of greater efficiencies are informed by their industry experience.

G. <u>Outage Restoration</u>

Ms. Alexander erroneously testified that PSO needed another phase of deployment to integrate its AMI system with its outage management system to reduce customer outage time, going so far as to state that she saw no reference to it in PSO's proposal "at all". (Alexander Supp. Resp. p. 15, LL 18-20, to p. 16, LL 1-5; Tr. 7-21, sd 238, LL 1-11.) Mr. Lewellen pointed out more than once that this benefit will be available immediately, and is included in PSO's forecasted costs. (Lewellen Supp. Rebut. p. 14, line 22 to p. 15, line 4, Tr. 7-22, lw 40, LL 3-8, lw 49 line 23, to lw 50, line 2; lw 50, LL 7-9 & 17-21.) Despite Ms. Alexander's misplaced assertion to the contrary, Mr. Lewellen's supplemental rebuttal testimony clearly stated "Outage order creation will be implemented as meters are deployed, which will quicken the dispatch of outage restoration resources and provide better communications about the restoration efforts." (Lewellen Supp. Rebut. p. 20, LL 27-29.)

H. Avoided Capacity

Ms. Alexander did not agree with PSO's use of a generation facility as proxy for the peak load reduction that it estimates will result from its consumer programs and argues that customers will not see the benefit of such reductions in their rates. (Alexander Supp. Resp. p. 17-19.) Ms. Alexander states that "the issue is not my objection to the modeling of future avoided capacity and energy costs. These are, in fact, appropriate manner – appropriate benefits to consider in the development of its consumer programs." (Tr. 7-21, sd 210, LL 20-24.) She took issue with the fact that she could not understand how such savings would be reflected in rates and that the proxy plant PSO used was not reflected in the IRP. (Alexander Supp. Resp. p. 18, LL 11-18, p. 19, LL 4-6; Tr. 7-21 sd 211, LL 6-11; sd 212, LL 4-6.)

Company Witness David Sartin refuted all of Ms. Alexander's arguments, including her incorrect assertion that PSO's IRP indicated it intended to rely on short-term purchases. "That was a part of the testimony that Ms. Alexander gave that we have been perplexed about. There is nothing in the testimony -- there is nothing in the IRP that says we're relying on short term purchases." (Tr. 7-22, lw 93 LL 13-16.) Mr. Sartin explained that PSO's IRP in fact showed a need for which PSO inserted a "placeholder that shows the deficiency that we have in being able to meet the SPP reserve margin requirements and then we describe in the IRP that we're continuing to review and look at the options available to us, including construction of new power plants . . . ." (Tr. 7-22, lw 88, LL 12-17.)

Mr. Sartin acknowledged that "there are no PSO promises as to a specified generation technology that will actually be avoided as a result of AMI." (Sartin Supp. Rebut. p. 12, LL 7-8.) Mr. Sartin continued:

> To make commitments at this time as to avoidance of specific plans for new generation is not prudent since PSO's plans for needed new generation supply are ongoing. The point of an avoided cost calculation is to estimate a reasonable level of costs that will not occur as a result of reduced capacity and energy. PSO selected a gas-fired peaking plant as a reasonable proxy for the costs to be avoided. This does not specifically mean that PSO will avoid construction of a power plant, but these costs can also represent the capacity and energy that PSO avoids if it purchased these in the market. (Sartin Supp. Rebut. p. 12, LL 8-15.)

He illustrated how PSO was reasonably providing a value for the avoided capacity enabled by AMI. As stated above, Ms. Alexander acknowledged the validity of including such a benefit. Mr. Sartin testified that PSO needed ". . . to figure out how to quantify the benefit of that, even though PSO hasn't selected the specific generation technology that we're going to go forward with today. So what we selected as a reasonable -- and actually a low cost option is a simple cycle combustion turbine power plant. And that is a lower per kilowatt installed cost of generation in particular compared to a combined cycle plant . . ." (Tr. 7-22, lw 89, LL 18-25.) These assumptions could be relied upon according to Mr. Sartin because the method used by PSO is consistent with two well established and accepted methods, the Proxy Unit method and the Peaker method. (Sartin Supp. Rebut. p. 12, LL 18-19.)

The ALJ agrees with Mr. Sartin that:

> The revenue requirement calculation is based on the recent estimated cost to construct a new simple-cycle combustion turbine, and estimated Southwest Power Pool (SPP) market around-the-clock energy costs. The combustion turbine generator is the least expensive type of generation to add to satisfy peak demand, with a lower initial installation cost than alternative generation options such as a combustion turbine combined-cycle unit. Given that most of the cost savings is from avoided capacity costs, by assuming a peaking generating unit, this estimate is conservative. (Sartin Supp. Rebut. p. 13, LL 5-11.)

Ms. Alexander took no position on the accuracy of the installed cost, energy cost, or estimated revenue requirement. (Sartin Supp. Rebut. p. 13, LL 14-15.) Accordingly, the ALJ credits PSO estimates of avoided capacity.

Mr. Sartin indicated how customers would see these benefits in rates: "By avoiding that generating plant costs, future base rate case applications for base rate increases will be reduced. And the fuel costs savings associated with that will flow to customers automatically through the Fuel Adjustment Clause." Mr. Sartin guaranteed that PSO would "flow through to the customers our actual costs, including the reduced costs associated with the power plants that we avoid." (Tr. 7-22, lw 94 l. 24 to lw 95 l. 4 & LL 16-19.) Mr. Sartin also pointed out that the IRP was filed in November 2013. The AMI proposal had not been finalized in time to be incorporated into the IRP, so the AMI-enabled reductions are not in that IRP. (Sartin Supp. Rebut. p. 14, 15-21.) The ALJ also credits PSO's explanation of how the savings from avoided capacity will flow through to customers.

I. Statistical Validity of PSO's Pilot Consumer Programs

In her written testimony, Ms. Alexander asserts that the data derived from the pilot program should not be relied on to justify full deployment and cost recovery. She argues, among other things, about the statistical validity of data from PSO's pilot Smart Shift programs. She asserts that because of enrollment levels and analysis based on a "simple" comparison of a control group of customers, the results were statistically invalid; Ms. Alexander wanted more information about the demographics, like income and household size rather than relying on average bill savings. (Alexander Responsive p. 13, l. 16, to p. 14, l. 20.) She also argued there was no evidence customers in the programs actually lowered their annual usage (Alexander Responsive p. 15, LL. 9-12.)

Mr. Lewellen testified that each control group was selected using standard experimental analysis and the validity of the control group to represent the participant group was verified by examining the hourly usage levels and patterns in a summer period prior to the participants' enrollment in the program. The usage pattern was so close that it is difficult to tell there are actually two separate profiles graphed. (Lewellen Rebuttal, p. 26, LL 15-22.) Analysis of demographic characteristics of participants provides little value in a load impact analysis, since the programs are voluntary opt-in programs. Analysis of impacts of the average of the participants opting into the program is a standard industry analysis method for determining impacts achieved from a program and, as the graphs in EXHIBIT DSL-2R show, the analysis provided clearly comparable and meaningful results. (Lewellen Rebuttal, p. 24, l. 23 to p. 25, l. 12.) It was true that the SMART Shift and SMART Shift Plus programs did not lower their annual usage, because that was not the intent of the programs. The programs gave participants the opportunity to shift their usage to different time periods, so it was not surprising that the customers did not lower their usage overall. (Lewellen Rebuttal, p. 25, LL 16-22.)

J. <u>The Use of Data from PSO's AMI Pilot, Industry Benchmarking, and AEP Sister Companies</u>

At the hearing on the merits, Ms. Alexander took issue with the pilot program not tracking bad debt and theft for AMI customers in the pilot versus non-AMI customers, not testing a prepay program, or not tracking automatic connects or disconnects specific to AMI meters, concluding the data tracked was insufficient to justify the broader deployment. (Tr. 7-21, sd 195, LL 10-12; sd 220 LL 13-16; sd 227 LL 11-12; sd 228 LL 19-21, sd 236, LL 15-21.) As explained above, Mr. Lewellen gave responses as to why certain data was not tracked during the pilot. The pilot was too small an area to meaningfully track a lot of the data Ms. Alexander preferred to be tracked, such as bad debt or prepayment programs; the difficulty in identifying theft manually on non-AMI meters; and PSO did not have the IT in place to track connects and disconnects with the granularity that Ms. Alexander required, but would be implementing the IT changes going forward. (Tr. 7-21, sd 100, l. 23 to sd 101, l. 1, Tr. 7-22, lw 64, LL 7-10; lw 65, LL 3-6, LL 13-21; lw 43, LL 3-10.)

PSO relied on data from the pilot where appropriate, but also industry benchmarking and lessons learned from other AEP operating companies to develop data and support for its proposal for AMI deployment:

> The real purpose of a pilot is no different [from] the definition of pilot. It is trying new technology and programs and to learn from them. And so we have learned a lot of different things from the pilot that [*sic*] helped us develop the overall plan from costing information to customer participations to how did customers respond to different tariffs. So we used that detailed information from the direct load control program, the time of day rates, their response in developing our benefits around demand reduction and energy reduction. . . . It is

> from a pilot you understand the cost of the technology, what it takes to put it in and the IT costs. So we took the lessons learned from the pilot, plus the experiences that we used from our other deployments across AEP from AEP Texas and Ohio, those lessons learned, costing information, and then also with our benchmarking of where things we didn't have in our pilot or be able to track that it is an industry practice using benchmarking to gather that information. (Tr. 7-22, lw 43, l. 17 to lw 44, l. 1; lw 44, l. 23 to lw 45, l. 6.

As Mr. Lewellen further explained:

> [W]e used information from the pilot and the actual load information [in] develop[ing the] cost benefit. We used benchmarking data of understanding around theft or bad debt of using -- because that is not -- we didn't track that during the pilot. But also information from lessons learned of -- AEP Texas was a million meter deployment, a very large deployment. So we learned from them and they shared information of how to -- costing information, how to implement project plans, all of those types of things. (Tr. 7-22, lw 45, l. 22 to lw 46, l. 6.)

Mr. Lewellen also pointed out the other information PSO learned from the pilot. For example, he explained that PSO learned in the pilot "where we used high temperature events and identified, I think, 21 locations where the meter again was subject to failure. We were seeing a high temperature or we're seeing voltage changes over time." (Tr. 7-22, lw 44, LL 11-15.)

So PSO refined its cost estimates, learned how the technology would work, and observed the qualitative benefits. Ultimately, Mr. Lewellen concluded: "we used information from the pilot where it is applicable. We used benchmarking data. But also we used information from our sister companies based upon their deployments and pilots. So we used a comprehensive approach to looking at all aspects of cost and benefit." (Tr. 7-22, lw 48, LL 6-11.) The ALJ finds that PSO's comprehensive approach to the use of the data to inform the broader deployment was reasonable.

K. Forecasts of Participation Rates for Consumer Programs

Ms. Alexander stated her view that PSO's "optimistic" assumption regarding participation rates in its consumer programs was incorrect. (Tr. 7-21, sd 194, LL 9-15.) However, Mr. Lewellen acknowledged that PSO experienced 3 to 4 percent in the pilot for a number of reasons including difficulties with education. (Tr. 7-22, lw 55 LL 5-7.) Mr. Lewellen referred to his pre-filed testimony where he explained that opportunities for customer education were limited during the pilot program. "For example, mass media such as newspaper, radio and television, or public events such as home and garden shows, could not be used since the message would be shared with a much larger group of ineligible customers, which could have potentially created confusion." (Lewellen Rebuttal, p. 30, LL 3-6.) PSO ultimately forecasted 8 percent over 5 years, "which we think is very conservative, because our sister company had similar programs and had an 8 percent -- 9 percent participation rate. So we think it is very realistic and attainable for our forecasted participation." (Tr. 7-22, lw 55, LL 7-11.)

The ALJ agrees. As explained above in part II. C., based on PSO's experience, the ALJ also credits PSO's position with respect to the issue of the effect of offering rebates towards thermostats will have on participation rates.

III. Consumer Education

The ALJ notes that Ms. Alexander initially asserted that PSO had not provided outreach and education plans as part of its filing, and that the education and outreach should be improved based upon pilot survey responses and program evaluation. (Alexander Responsive, p. 19, LL 3-6, p. 23, LL 10-13.) Mr. Lewellen explained in response that:

> When this case was originally filed, PSO's customer education and communication plan was still in development. As stated in the Application, PSO was mandated by the Commission to file this base rate case no later than January 18, 2014. However, since the filing was made, PSO has completed its initial customer education and communication plan, which I have included as EXHIBIT DSL-1R. Based on PSO's experience and lessons learned from the pilot, as well as information gleaned from PSO's sister companies and other utilities that have deployed AMI, we are confident that our plans to reach customers will be effective, proactive, and engaging. During the pilot program, the opportunity to provide customer education on programs was limited. For example, mass media such as newspaper, radio and television, or public events such as home and garden shows, could not be used since the message would be shared with a much larger group of ineligible customers, which could have potentially created confusion. The customer education program will help our customers understand our proposed AMI deployment, what they can expect once they have AMI, how they can participate in AMI-enabled tariffs and programs, processes available if they have questions or concerns, and the expected benefits of AMI. (Lewellen Rebuttal, p. 29, l. 17, to p. 30, l. 10.)

Mr. Lewellen adequately explained the evolution of PSO's education and outreach plan.

IV. Qualitative Benefits

Ms. Alexander also discounts the qualitative benefits of the deployment because they are not quantified with a dollar value. (See, e.g., Alexander Supp. Resp. p. 28, LL 8-12.) These benefits include increased customer education and satisfaction due to the web portal, related tools, and home energy reports; power outage detection through real-time access, quickening dispatch of restoration resources, finding nested/pocket outages in large events, ensuring power is restored; remote reading of meters for moving customers and billing inquiries, faster credit reconnects (minutes versus up to 24 hours); remote service connections; elimination of estimated meter readings which reduces customer complaints; no need to access customer yards, avoiding inconvenience to customers and safety hazards; correcting issues prior to an outage occurring; consumer programs that allow customers to save money and reduce energy and capacity use; and facilitating developing technologies. (See, e.g. Lewellen Supp. Rebut. p. 20, l. 4, to p. 22, line 30.)

More specifically, benefits of AMI include: PSO will be able to process credit reconnects automatically. In 2013 PSO performed over 40,000 credit reconnects, and 88,000 residential service connects for move-ins and PSO would be able to process 90% automatically within minutes versus 24 hours for non-AMI meters. In 2013, PSO experienced 200,000 skipped meter reads due to access issues or other hazardous conditions resulting in 190,000 estimated bills. PSO would virtually eliminate these estimated meter reads, which would also reduce complaints as a result. PSO would virtually eliminate visits to customers' yards (of which PSO personnel made 6.75 million in 2013.) PSO would avoid about 1.5 million hazards, such as bad dogs and vicious pit bulls. Additionally, in 2013, PSO field employees drove over two million miles, and 75% of these miles driven would be eliminated by AMI. (Lewellen Rebuttal p. 19 to 20.) These are real benefits, not theoretical as asserted by Ms. Alexander. (Tr. 7-21, sd 192, l. 3, l. 13)

Ms. Alexander understates the inherent value of these benefits. But Mr. Sartin illustrated the value of these benefits:

> The qualitative benefits the AARP summarily dismisses are hugely beneficial for customers. They have value. Can I quantify them? No. But what's the value to an AARP customer or any of our customers to getting their power restored more quickly? It is valuable. . . . Taking all of our meter readers and meter technicians from the streets of Tulsa, walking through backyards, the risk that they take on a day-to-day basis, again, that is important. It is important to our employees, it is important to our customers." (Tr. 7-22, lw 100, LL 4-8, lw 101, LL 2-7.)

More modern distribution and metering system with more accurate billing, fewer estimates and resulting complaints, fewer outages through finding outages before they occur and remedying outages quicker, and giving customers pricing options that allow them to save money and help the environment are all valuable to customers. These benefits inure to the customers and cannot be ignored. As PUD Witness Thompson testified the cost benefit analysis is just "one of the factors" leading to PUD's support of the AMI program; it also is "what it can do for the system, how it helps the consumer as well as the company with information to support the system." (Tr. 7-21, sd 139, LL 21-25.)

V. Use of a Rider to Recover the Costs of the AMI Deployment

Ms. Alexander objected to PSO's proposed cost recovery mechanism to recover AMI deployment costs, arguing "This rider will recover the bulk of the costs from customers before there is any determination of theoretical ability to look at the prudency of this system. It turns the burden of proof on its head and results in risks entirely borne by customers that they alleged in theoretical benefits will actually occur. [sic]" (Tr. 7-21, sd 192, LL 7-12.) Ms. Alexander also argues that the tracking mandated by the Second Joint Stipulation is inadequate to confirm all the benefits that PSO has estimated in arguing for a rider. (Tr. 7-21, sd 200, LL 5-10.)

What Ms. Alexander gets wrong is what a rider accomplishes. Mr. Sartin analogizes to the Commission's reviews of utility Fuel Adjustment Clauses:

> On an annual basis the full adjustment clause is roughly $600 million a year every year, as opposed to AMI, which is a one-time expenditure. And just because we have the right to recover costs through that fuel adjustment clause doesn't mean that we get a free pass with no scrutiny. There is severe scrutiny [sic] on the Fuel Adjustment Clause. We provide a package of information to Staff, Staff comes over to Tulsa to review the information with our accounting staff, they travel to Columbus, Ohio to meet with the people that actually procure our natural gas and then coal supply and then transportation contracts. So it is a pretty complete process. And what I would expect with the review of the AMI tariff is a similar inspection on an annual basis. (Tr. 7-22, lw 78, l. 17 to lw 79, l. 6.)

As Mr. Sartin further explained:

> The OCC will have ample opportunity to review and approve AMI costs during the time the AMI rider is in place and thereafter. PSO seeks an AMI rider to match the timing of the costs to customers of the AMI program with the benefits customers receive as the new meters and other assets are installed and placed in service for their benefit. Because of the opportunity for review afforded the OCC and other parties as PSO files updates to the annual AMI costs, the AMI rider will certainly not be "baffling and expensive for consumers and burdensome for regulators" as Ms. Alexander fears. Instead, information will be provided more frequently than would be the case if AMI were only considered in a base rate case. (Sartin Rebuttal, p. 7, l. 19, to p. 8, l.5.)

Thus, Ms. Alexander is incorrect when she states: "But they are not tracking [benefits] or promising with any risk to them that they will actually occur". (Tr. 7-22, lw 28, LL 20-22.) Just as in fuel reviews, (see OAC 165:35-35-1(b), PSO will bear the burden of proof. "We have approved a mechanism to collect dollars from the consumers, but we have not approved the dollars the company will spend. So, when that time comes to true-up when it comes time to roll into -- excuse me -- those are in PSO's next general rate proceeding we will be reviewing those costs." (Tr. 7-21, sd 116, LL 6-11 PUD Witness Thompson.)

As pointed out above, PSO does bear the risk that the benefits will be delivered in that, as explained by Mr. Sartin, PSO's deployment will be subject to Commission review, where the Commission will determine prudence and whether the program is yielding benefits. This is different than the approval granted to Oklahoma Gas and Electric Company in Cause No. PUD 201000029, *In the Matter of the Application of Oklahoma Gas and Electric Company For An Order of the Commission Granting Pre-Approval of Deployment of Smart Grid Technology in Oklahoma and Authorization of a Recovery Rider and Regulatory Asset.* In that cause, OG&E requested, and was granted via Final Order No. 576595, not just a rider to facilitate cost recovery, but preapproval that its deployment was "fair, just and reasonable and represents a prudent investment by OG&E and, when constructed and placed in service, will be used and useful to OG&E's customers." See Order at Para. 5, p. 17.

Ultimately, PSO has to, with respect to its AMI deployment expenditures, "come back into the Commission, show that those were prudently incurred and they are reasonable and seek the Commission's authorization at that point in time that those are reasonable and necessary and includable in the rate base." (Tr. 7-21, sd 48, l. 23 to sd 49, line 3.) Mr. Sartin assured the Commission that "we have every incentive to track those costs in order to make a – to prove our case when it comes before the Commission for a used and useful determination." (Tr. 7-22, lw 81, LL 5-8.)

PSO will have to present evidence that will satisfy this Commission. So Ms. Alexander's concerns about whether tracking will be sufficient, whether benefits will actually accrue, and whether costs are prudently incurred can and will be addressed by the Commission in the proceeding in which PSO proposes to finally recover the costs and include them in rate base.

VI. Guaranteed Savings and Future Savings

Ms. Alexander asserted that there was no justification for the $11 million guaranteed savings that PSO intends to credit to the proposed AMI rider. (Tr. 7-22, lw 27, l. 20 to lw 28, line 2.) She also suggested that any savings beyond the $11 million might not accrue to customers. (Tr. 7-21, sd 135, LL 1-8.) It was explained multiple times that the $11 million in guaranteed savings reflected O&M savings of $5 million during the deployment and $6 million in O&M savings in the fourth year. (Lewellen Supp. Rebut. p. 9, LL 17-20; Lewellen Rebut. p. 6, LL 1-10). Mr. Sartin similarly explained it encompassed labor, vehicles and overheads. (Tr. 7-21, sd 56, LL 14-23.)

Mr. Sartin testified as to how guaranteed and further savings would flow to customers:

> It is important to note, too, that of those guaranteed savings, they don't stop at the end of the four year implementation period. Now the guarantee [sic] part of them does come off. But whatever those actual

> savings are thereafter, those will flow to customers as a part of the normal ratemaking process. As far as the other savings that will come to the company and be flowed through to the customers, there is the avoidance of fuel costs as customers use less energy as a part of the AMI tariffs and that will flow through the normal Fuel Adjustment Clause and happen regularly on an annual basis. And then as far as the avoided capacity costs, those will also flow to customers through the normal rate base process -- rate base -- rate case process. (Tr. 7-22, lw 81, l. 16 to lw 82, l. 5.)

The ALJ finds that PSO made reasonable assumptions to develop its cost benefit analysis and adequately demonstrated how the benefits will flow through to its customers.

VII. Conclusion

In conclusion, as Ms. Alexander herself concedes:

> Oh, absolutely there are benefits. And we have dueling testimony about what those benefits are. But I certainly agree that there are benefits. They will reduce labor costs. It will reduce truck rolls. It will provide a more efficient way to avoid visiting the meter for any connection or disconnection. There are significant savings for those operational programs. There will also be some benefits from their customer programs. There will be some peak load reduction. There will be some people who participate in those programs. (Tr. 7-22, lw 26, LL 9-20.)

Accordingly, there are benefits to AMI to customers.

As Mr. Sartin explained, PSO "started with fairly modest pilot programs in Owasso and then we expanded those to Sand Springs, the University of Tulsa, the City of Okmulgee. So, we have taken measured steps to ensure that we know what we are doing and that the program is producing the results that we expected it to." He explained further, "Now, what the plans are hereafter is again to take a measured approach and not try to get all this done in a very short compressed period. That's why the time period that we're talking about of rolling out for the rest of our customers is extended over a three-year period." Mr. Sartin agreed that PSO would "if something occurred during the process of doing this on an incremental basis that -- that [it] would be re-evaluating how things are actually going . . . that might necessitate some type of adjustments." (Tr. 7-21, sd 65, l. 21, to sd 66, l. 11.)

Thus, PSO has pursued a measured approach to phasing in the rollout of AMI meters in its service territory and explained the value of its measured approach in rolling out AMI, first in the pilot areas, reviewing its own data plus that of sister companies and the broader industry. PSO adequately explained its plans for continuing that approach in a broader rollout.

PSO presented the testimony of experts who respectively, have decades of electric utility industry experience in accounting, finance and regulatory and electric utility operations. These experts explained the quantitative and qualitative benefits of AMI, and how PSO's assumptions in developing its cost benefit analysis were reasonable. PSO acknowledged that there are some difficulties inherent in estimating the benefits of the AMI meters:

> As Ms. Alexander notes at p. 25 of her testimony, PSO has communicated that not all of the future cost savings will be able to be quantified without some estimation. This is very common because there is no accounting system that tracks costs that do not occur. Rather, accounting systems are designed to track and accumulate actual costs, which is why tracking actual AMI costs will be readily achieved and reported to the OCC. The benefits will also be reported, but will require some estimation because as previously described accounting systems do not track costs that do not occur, and also because there will be other changes to PSO's costs that impact the various AMI cost savings categories, which have nothing to do with AMI. For example, while PSO will experience reductions in bad debt expense from AMI, bad debt expense is also impacted by the weather, economic conditions, the level of the fuel clause adjustment factor, and other items. Discerning the specific impacts on bad debt expense from AMI alone will require some reasonable estimation. (Sartin Supp. Rebut. p. 8, LL 8-21.)

However, as Mr. Sartin explained:

> PSO has fairly determined each of the underlying assumptions for each cost and benefit item with no significant high or low bias, although if anything PSO erred on the cautious side of the assumptions so as to be conservative with the results. . . . Most assuredly, the actual costs and benefits will not be precisely as PSO predicts because predicting the future is uncertain. However, we have used reasonable assumptions that are expected to approximate future reasonable results. (Sartin Supp. Rebut. p. 10, LL 7-17.)

PSO also pointed out that AMI is a proven technology in use for about half the country's utility customers. (Sartin Supplemental Rebuttal p. 4, LL 12-13; Tr. 7-21, sd 52, LL 24-25.)

Witnesses for PUD and AG pointed out that not just the quantitative benefits of AMI, but the qualitative benefits in garnering their support for the deployment, as did counsels for OIEC, Walmart and QSC. Counsel for QSC specifically pointed out the positive implementation in the pilot area of Owasso, a municipal member of QSC. The ALJ also acknowledges the Commission's findings regarding the benefits of AMI in Cause No. 201000029. Ms. Alexander admittedly never found an AMI deployment she supported.

For the foregoing reasons, the ALJ finds PSO's proposed AMI deployment and cost recovery, subject to further Commission review, is reasonable.

(2) Placing Distribution Automation and Volt/Var Capital Costs in rate base.

Ms. Alexander recommends the Commission reject PSO's request for recovery of Distribution Automation and Volt/Var capital costs in rate base because she felt "the programs have not documented any of the benefits or results that were originally promised for these pilot programs due to failures in operations or management that resulted in insufficient data." (Alexander Responsive, p. 27, LL 5-9.) Ms. Alexander acknowledges that she had not reviewed the Company's most recent Volt/Var evaluation report for 2013, though it was provided before she prepared her written direct testimony. (Alexander Responsive, p. 26, n. 35.) This report showed significant performance improvements between the 2012 evaluation and the 2013 evaluation. Mr. Lewellen testified that the "results highlight the potential benefits of a well-functioning VVO system. These improvements include an energy reduction on a per-feeder-basis of approximately 2% to 7%. Also, the analysis showed that the VVO successfully controlled power factor at the feeder level to within 0.02 of unity power factor" which he stated were due to enhancements to the VVO system in the spring of 2013 in anticipation of improving summer 2013 performance. (Lewellen Rebuttal p. 35, LL 6-19.) Mr. Lewellen clarified that "in 2012 we showed positive results, but it wasn't the level that we were expecting. And so, based upon lessons learned and improvements, we saw a double -- doubling effect of the improvements of the performance we saw from volt/var." (Tr. 7-21, sd 98, LL 4-8.) Ms. Alexander's criticisms are not well taken, and the ALJ recommends the Commission allow the placing of those capital costs in rate base.

(3) Disconnection Rules.

Ms. Alexander testified that the Commission had approved PSO's request for a waiver from the current regulations on disconnection for non-payment in Cause No. PUD 201100083 (Order No. 589969, October 13, 2011) with the obligation of PSO to attempt a phone call to the customer at least 48 hours prior to the disconnection and to include information on the disconnection notice that a premises visit will not be conducted to disconnection service when a smart meter is present. (Alexander Responsive, p. 28, LL 7-11.)

Ms. Alexander did not agree to the elimination of premise visits. According to Ms. Alexander, any required premise visit, notice, or in-person contact attempts are important consumer protections that are designed to prevent disconnection for nonpayment where possible. Ms. Alexander testified that the disconnection of electric service is dangerous to household health and safety and this step should be viewed as the last resort and not the first resort. (Alexander Responsive, p. 28, LL 16-18.)

Ms. Alexander testified that PSO stated in an answer to a data request that it cannot provide information that would allow for a review of the frequency or incidence of disconnection of customers with or without advanced meters. (Alexander Responsive, p. 29, LL 6-8.)

She recommended that if the Commission rejects the Company's proposal to fully deploy the advanced metering system, the waiver of the regulations should be reversed and PSO should be required to implement the same consumer protections for its pilot advanced metering customers as are required for other residential customers. (Alexander Responsive, p. 30, LL 2-5.)

If PSO is allowed to continue its waiver for its existing advanced metering customers, she recommended that the Commission require PSO to track the incidence of disconnection of service for nonpayment of residential advanced metered customers so that such information can distinguish the presence of an advanced meter and report this information quarterly to the Commission and other interested parties. Furthermore, she recommended that the Commission require PSO to provide basic information on customers with advanced meters with regard to late payment, payment plans, and overdue bill amounts compared to other residential customers in order to determine if PSO's attempts to contact such customers, and avoid disconnection of service, is sufficient in light of the elimination of the premise visit. (Alexander Responsive, p. 30, LL 8-17.)

Mr. Lewellen testified PSO's proposed AMI deployment would not reduce or degrade consumer protection policies associated with disconnection for nonpayment. As PSO discussed in discovery response AARP 1-21, PSO's procedures regarding disconnection for nonpayment strictly follow the requirements set forth in OAC 165:35-21-Disconnection of Service and for those customers with AMI meters, Order No. 589969 of Cause No. PUD 201100083. For residential customers, regardless of the type of meter they have, if a bill is not paid by the due date, the first disconnect notice is mailed to customers with their next month's bill. This notice satisfies the minimum ten-day requirement found in OAC 165:35-21-20(b.) To satisfy the minimum 48-hour notice required by OAC 165:35-21-20(c), a second disconnection notice is scheduled to be mailed 12 business days after the first notice. Additionally, though not required by the Commission's Electric Rules, PSO contacts customers by telephone 48 hours prior to disconnect to notify them that they need to contact PSO regarding their service. When the customer contacts PSO, they are then informed that their service is subject to disconnection. (Lewellen Rebuttal, p. 31. LL 20-23, p. 32, LL 1-13.)

According to Mr. Lewellen, the only premises visit that PSO is required to make is to leave a disconnect notice at the premises at the time of disconnection for those customers without an AMI meter. PSO generally does not attempt contact with the residential customer at the time of the disconnection of service. Mr. Lewellen testified that as could be seen from PSO's disconnection policies, customers are given ample communications and time to avoid the disconnection. Furthermore, if a customer with an AMI meter is disconnected for nonpayment, having an AMI meter allows them to have their service restored within minutes instead of up to 24 hours once payment has been made at an authorized pay station. (Lewellen Rebuttal, p. 32, LL 14-22.)

Mr. Lewellen testified that the source and requirements for creating disconnect notices and ultimately a credit disconnect, if needed, is created in the same back office system. The only difference is the method of the credit disconnect, either in the field by a Meter Revenue Operations specialist or automated via the AMI disconnect switch. The process and back office system for creating disconnect notices for both AMI and non-AMI customers are the same. Only the actual physical disconnection is different between the two meter types. (Lewellen Rebuttal, p. 33, LL 1-7.)

During cross-examination, Ms. Alexander stated she knew PSO's policy was not to have PSO employees receive money or checks for payment of electric bills. (Tr. 7-22, lw 14, LL 15-18.)

She had not inquired to the Consumer Services Department of the Commission as to whether or not they had any adverse response to PSO's disconnect procedures over the last three years. (Tr. 7-22, lw 14, LL 20-24.)

The ALJ finds that no change from the Commission's Order 589969 issued in Cause No. PUD 201100083 is needed at this time. There was no evidence presented by AARP that sufficient customer protections are not currently in place for disconnection of a customer with an AMI meter for nonpayment.

(4) Use of Riders.

Ms. Alexander testified that if the Commission should allow PSO to recover advanced metering project costs in the future, that such rate recovery not be implemented through a surcharge or rider, but rather considered in the context of a traditional base rate case where all costs and benefits could be identified and evaluated prior to allowing cost recovery or a finding of prudency. (Alexander Responsive, p. 31, LL 8-12.)

Ms. Alexander testified that in her opinion, in the past, surcharges were only approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if not addressed outside of a base rate case, could threaten to harm a utility's financial health. Examples of such surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for other types of surcharges and tracking mechanisms by utilities have significantly increased in Oklahoma and elsewhere. Indeed, according to Ms. Alexander, the National Regulatory Research Institute in 2009 characterized the use of cost trackers and mechanisms as the "latest trend". (Alexander Responsive, p. 31, L. 22 – p. 32 LL 1-8, footnote 42, p. 32.)

With regard to surcharges and riders generally, she recommended that the Commission carefully consider whether they are necessary and eliminate them where reasonable. Where costs are transferred from a surcharge cost recovery methodology to base rates, she recommended that the project or investment first be evaluated carefully to determine that the underlying program had been implemented in a cost effective and efficient manner and that the current costs being recovered in the surcharge or rider properly represent a reasonable level of recurring costs that should be included in a revenue requirement going forward. (Alexander Responsive, p. 33, LL 15-17, p. 34, LL 1-5.)

Mr. Sartin testified that while Ms. Alexander indicated that riders should be the exception rather than the rule, appropriate use of riders by the OCC has occurred on a regular basis, and is common throughout the electric utility industry. These riders run the gamut of various electric utility costs across the country including fuel, purchased power, taxes, pension, demand side management, vegetation management, environmental compliance, generating plants, off-system sales margins, and others. Some retail jurisdictions even have full cost of service formula rates, which is the case for Southwestern Electric Power Company's Louisiana jurisdiction. It is also the case for Oklahoma Natural Gas and CenterPoint Energy, both under the OCC's jurisdiction. (Sartin Rebuttal p. 8, LL 17-23, p. 9 LL 1-3.)

During cross-examination Ms. Alexander stated she did not have any evidence that the Commission staff had been derelict in their duties to review riders. (Tr. 7-22, lw 16, LL 5-7.)

Ms. Alexander further testified that she was not aware of the Oklahoma Statutes allowing periodic rate adjustments for transmission upgrade costs and environmental plant costs without a full rate case. (Tr. 7-22, lw 16, LL 8-15.) She stated if that was the policy, it is what the Commission should adhere to. (Tr. 7-22, lw 16, LL 16-17.)

The ALJ finds the use of riders is a policy decision for the Commission and that the Commission has historically provided substantial review and monitoring of costs that are placed in riders and recovered from customers.

(5) Residential Base Service Charge.

AARP witness Alexander opposed PSO's residential base service charge increase from \$16.16 to \$20.00. (Alexander Responsive, p. 34, LL 12-13, LL 17-18.)

According to Ms. Alexander an increase in the minimum customer charge for residential customers was not appropriate for the following reasons:

i) PSO's proposed monthly customer charge at \$20.00 would significantly exceed the \$13.00 customer charge in effect for Oklahoma's other large investor owned utility OG&E.

ii) Shifting costs to fixed charges sends the wrong signal to customers about the value and impact of efficiency actions because the increase in the monthly customer charge eviscerates the impact of taking actions to reduce consumption or purchasing newer and more efficient appliances, both of which are central to the Company's efficiency programs and promoted in their website and education materials.

iii) Fixed customer charges are particularly harmful to lower use customers whose monthly bills increase at a higher percentage rate than higher usage customers.

iv) In general, lower income and elderly customers have lower usage than the average residential customer due to smaller dwellings, and, with respect to the 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. (Alexander Responsive, p. 35, LL 3-19, p. 36 LL 1-6.)

PSO witness Jackson responded to Ms. Alexander. She testified that to the first reason given by Ms. Alexander, while PSO and OG&E are both investor-owned utilities in Oklahoma, the two companies have different service areas, costs, cost allocation, rate design, and composition of the monthly fixed charges. Comparison of the OG&E residential *customer charge* with PSO's residential *base service charge* is not relevant to the review of the appropriateness of the proposal to include additional fixed distribution costs in the fixed base service charge. A customer charge and a base service charge are not equivalent according to Ms. Jackson. (Jackson Rebuttal, p. 5, LL 21-22, p. 6 LL 1-6.)

Regarding the evisceration of efficiency actions to be caused by an increase in fixed charges, according to Ms. Jackson, Ms. Alexander actually unwinds her own argument. Ms. Alexander states in her testimony that distribution charges reflect only a portion of the overall monthly charges and generation supply typically represents over 50% (sometimes 60-70%) of the monthly bill charges. Ms. Alexander recognizes that there is ample usage related to generation, transmission, and the remaining portion of distribution service not included in the base service charge subject to the efficiency actions taken by customers. Further, fixed costs by definition are incurred regardless of the level of consumption and to the extent those costs are recovered through an energy charge, a false price signal is actually being sent. PSO does not agree that its proposal to move more fixed costs into the base service charge removes the incentive to engage in energy efficiency activities. (Jackson Rebuttal, p. 6, LL 7-19.)

Ms. Jackson further testified that as to the third and fourth reasons given by Ms. Alexander, PSO did propose to increase the residential base service charge to $20.00 from the current $16.16. As part of that proposed rate design, the first-step energy rates were decreased from the current per kWh rates to account for the additional movement of fixed distribution costs from the variable energy charge to the fixed base service charge. For a typical residential customer, this rate design adjustment alone (not including AMI tariff charge) results in no change to the base bill. (Jackson Supplemental Testimony, p. 8, LL 8-10.) Contrary to Ms. Alexander's argument that low-income customers equate to low-usage customers, PSO customers receiving Low Income Home Energy Assistance Program (LIHEAP) payments actually use close to the average of all residential customers, which, in this case, is a monthly average of approximately 1,139 kWh. (Jackson Rebuttal p. 6, LL 20-22, p. 7 LL 1-6.)

Ms. Jackson further testified that PSO had made rate design proposals that recognize and are mindful of customer total bill impact. PSO's proposed revenue distribution tempers the increase to the residential class required to achieve an equalized return as directed by the filed cost-of-service study, in recognition of customer impact. (Jackson Rebuttal, p. 7, LL 7-11.)

During cross-examination, Ms. Alexander testified she understood that unregulated rural electric cooperatives fees and charges are set by directors of the cooperative who can be voted out by the ratepaying members. (Tr. 7-22, lw 18, LL 15-20.) When asked about the monthly charge of unregulated electric cooperatives, Ms. Alexander was unaware that North Fork Electric had a $26.00 monthly charge, Cotton Electric had a $29.50 charge, and Kiamichi Electric had a $30.00 monthly minimum bill. (Tr. 7-22, lw 18, LL 21-25, lw 19, LL 1-2.) Ms. Alexander was also unaware that Oklahoma Natural Gas had a monthly service charge of $28.76. (Tr. 7-22, lw 18 LL 4-6.)

The ALJ finds that the increase in the base service charge from $16.16 to $20.00, and the accompanying reduction in the kilowatt-hour charge, is reasonable. The testimony of Ms. Jackson is convincing that $20.00 is a reasonable charge which will still have the majority of fixed costs being recovered on a kilowatt-hour basis, thus minimizing the impact of the collection of fixed costs on low use customers.

(6) AARP's Low Income Proposal.

AARP witness Alexander testified that PSO should be required to offer a low income bill payment assistance on a monthly basis similar to that of OG&E. (Alexander Responsive, p. 38, LL4-7.) OG&E's tariff provides a $10.00 monthly discount for customers who qualify for assistance under the Low Income Home Energy Assistance Program (LIHEAP) implemented by the Oklahoma Department of Human Services. (Alexander Responsive, p. 37, LL 17-21.) In 2010 OG&E had 44,152 customers who received LIHEAP discounts. (Alexander Responsive, p. 37, L 21 – p. 38 L.1.) The annualized cost of the program is approximately $5.7 million. (Tr. 7-21, p. sd 184, LL 19-24.)

PSO witness Jackson testified that if PSO were to propose a $10.00 monthly discount for the same level of LIHEAP customers on PSO's system the subsidy would be $445,120 per month or $5,341,440 per year. (Rebuttal, p. 8, LL 3-5.) According to Ms. Jackson, this funding level would have to be subsidized by other customer classes that may not be agreeable to this proposal. (Jackson Rebuttal, p. 8, LL 6-7.)

PSO witness Sartin testified that PSO understands the important societal issues for some of the low income customers to be provided financial assistance for their needs, including their needs for electric service. PSO believes such assistance should continue to come from the variety of existing governmental and social agencies who are experts in providing such assistance. (Sartin Rebuttal, p. 27, LL 6-10.)

Mr. Sartin testified that PSO had supported agencies throughout its service territory by contributing over $5 million over the past 5 years in the areas of education, hunger and housing, community and neighborhood, arts and culture, youth, business, and others. PSO and its employees are active in the communities served, and take leadership roles in many such organizations including the United Way, American Red Cross, and many others. PSO is recognized for its positive community involvement throughout its service territory. (Sartin Rebuttal, p. 28, LL 3-9.)

Mr. Sartin testified that through PSO's Power Forward energy efficiency and demand response programs customers have the opportunity to reduce their electric bills. Details of these programs could be found on PSO's Power Forward Web site http://powerforwardwithpso.com. Included in these programs, as required by OAC 165:35-41-4(b)(1), is the Efficiency Outreach Program that provides attic insulation, caulking and weather stripping, and air sealing for qualifying low income customers with household income less than $35,000 per year. Currently, PSO provides this service to approximately 1,500 customers per year. (Sartin Rebuttal, p. 28, LL 12-19.)

Mr. Sartin further testified that PSO offered several bill assistance options: (1) extended payment agreements permit customers to pay off their balances in three monthly installments; (2) the average monthly payment plan permits customers to spread the monthly ups and downs of electric service on an average basis across 12 months; and (3) third party notification provides a designated contact copies of the account holder's billings in the event their account should become delinquent. In addition, PSO's Customer Operations Center maintained lists of agencies that provide assistance to customers in need of help meeting their financial obligations, which are provided to these customers when they contact PSO. (Sartin Rebuttal, p. 29, LL 4-12.)

PSO also supported the Light A Life Energy Fund which was created in 1986 in partnership with the Salvation Army. This fund is supported by contributions from PSO and individuals, and contributions are administered by the Salvation Army, which determines the need and assistance to be provided. In addition to providing some of the funding, PSO's role is to help advertise the program and develop mechanisms through which customers can make donations. PSO advertised through bill inserts, the psoklahoma.com website, and newspaper and magazine ads. (Sartin Rebuttal, p. 29, LL 13-19.)

In cross-examination, Ms. Alexander testified her recommendation for the PSO discount to be provided to LIHEAP customers would be a ratepayer- funded discount. (Tr. 7-22, lw 9, LL 6-8.) The public notice did not include AARP's proposal of the ratepayer funded discount. (Tr. 7-22, lw 9, LL 12-17.) Ms. Alexander denied her proposal would be a redistribution of PSO's customers' income. (Tr. 7-22, lw 10, LL 3-5.) Ms. Alexander believed her proposal was no different than asking customers to pay for poles and wires. (Tr. 7-22, lw 10, LL 7-11.)

Ms. Alexander was not aware of the Oklahoma Supreme Court decision addressing the issue of requiring utility customers to pay for involuntary charitable contributions. (Tr. 7-22, lw 12, LL 19-23.)

PSO counsel noted for the record the case of *State v. Oklahoma Gas & Electric Company*, 536 P. 2d 887. (Tr. 7-22, lw 13, LL 1-2.)

Based upon the evidence presented the ALJ does not find AARP's rate-payer funded discount of over $5 million reasonable. As explained by PSO witnesses Sartin and Jackson, there are different means of providing assistance to low income customers, such as the Efficiency Outreach Program, other than a direct rate-payer funded discount as advocated by AARP.

(7) System Reliability Rider (SRR).

Ms. Alexander filed Rebuttal Testimony in response to the testimony filed by PSO Witness Steve F. Baker and Robert Thompson on behalf of PUD with regard to the treatment of PSO's vegetation management costs currently recovered in a Rider. (Alexander Rebuttal, p. 1, LL 12-15.) PUD witness Thompson subsequently supported Joint Stipulation 1 that left the SRR unchanged.

Ms. Alexander stated that Mr. Thompson had recommended that the $14.9 million currently recovered through a Vegetation Management Rider be included in rate base and that, with the $5 million amount for this purpose already in base rates, the Commission approve an expenditure of $20 million for vegetation management per year in base rates thus eliminating the current Rider method for cost recovery. (Alexander Rebuttal, p. 2, LL 1-5.)

Ms. Alexander recommended that the Commission not approve an additional $20 million in base rates at this time. Rather, she recommended that the Commission undertake an audit or other focused examination of the expenditures, both capital and O&M, currently being collected in this Rider and affirmatively decide whether a recovery of $20 million in base rates is appropriate in light of the original amended purposes of this Rider. (Alexander Rebuttal, p. 4, LL 7-11.)

Mr. Steven F. Baker filed Rebuttal Testimony to Mr. Thompson's Responsive Testimony that addressed the issues contained in Ms. Alexander's Rebuttal Testimony.

According to Mr. Baker the System Reliability Rider (SRR) has been in place since 2005; however, the scope of the rider has evolved over the years. Initially, the rider was strictly for vegetation management (Cause No. PUD 200300076); it was later amended in Cause No. PUD 200500515 to allow for the recovery of undergrounding; the recovery amounts were increased in Cause No. PUD 200800144 to allow for a separate funding cap for overhead to underground activities; and very recently, the Commission issued an order in Cause No. PUD 201300202 to expand the purpose of the rider to also include system hardening and grid resiliency activities. (Baker Rebuttal, p. 4, LL 16-23.)

In its current form the SRR provides for the recovery of $23.685 million of vegetation management, system hardening, and grid resiliency O&M costs. This amount is incremental to the costs currently included in base rates for vegetation management ($6.285 million.) The rider also allows for recovery of $7.7 million of carrying costs associated with overhead to undergrounding and system hardening and grid resiliency capital costs. (Baker Rebuttal, p. 5, LL 7-12.)

According to Mr. Baker, even the lowest amount of vegetation management expense for the prior four years ($21,907,696) was still higher than Mr. Thompson's recommendation of a total vegetation management level of $20 million. This fact still holds true even if Mr. Thompson's current base level of vegetation management expense amount of $5 million is corrected to the actual Commission-approved base amount of $6.285 million. In fact, PSO is currently projected to spend approximately $24 million in 2014 on its vegetation management program. With insufficient funds, PSO will be challenged to maintain the current four-year vegetation management cycle on its entire distribution system. (Baker Rebuttal, p. 8, LL 1-9.)

According to Mr. Baker, locking vegetation management spend into a set amount counters the very purpose of the recent expansion of the rider, which was to increase PSO's flexibility in terms of how to effectively maintain the reliability of the distribution system each year. Further, the costs are not "known and measurable" going forward. PSO's vegetation management expenses fluctuated by almost 15% over the past four years. The variation in vegetation management spend year-to-year is directly related to the thickness of vegetation within the areas being trimmed; thus it cannot be characterized as stable. (Baker Rebuttal, p. 8, LL 15-23.)

Mr. Baker testified that PSO had proven that it can effectively manage its vegetation management program costs, satisfy OCC requirements, and produce significant reliability benefits for customers through the rider. The current quarterly rider review process has provided considerable oversight of expenditures, planned work, and benefits. Also, with costs fluctuating, the rider guarantees that customers only pay for OCC-approved expenses incurred on a quarterly basis. Finally, maintaining the rider ensures that PSO has the necessary flexibility it needs to maintain not only its four-year vegetation management cycle, but also complete other reliability activities, such as its system hardening and grid resiliency efforts. (Baker Rebuttal, p. 11, LL 6-14.)

Mr. Baker further testified that the current review process established as part of the rider to track and monitor PSO's vegetation management expenses has proven to be an effective method and should be maintained along with the rider. This process has provided the Commission and PUD with all of the detailed vegetation management information, including expenses, necessary to review PSO's vegetation management costs for reasonableness and prudency. (Baker Rebuttal, p. 12, LL 12-17.)

The ALJ finds the recommendations of Ms. Alexander as not being supported by factual evidence. No place in her testimony does she point to one example of poor or inadequate oversight of SRR expenditures by the Commission staff. As stated earlier, Ms. Alexander stated she did not have any evidence that the Commission staff had been derelict in their duties to review riders. (Tr. 7-22, lw 16, LL 5-7.) It is further clear that she did not realize that PSO's costs for vegetation management have been and are projected to be well above her "significant concern" to include $20 million in base rates. The ALJ sees no reason to find that the Commission should change its findings made in Order No. 620006 issued in Cause No. PUD 201300202 on January 7, 2014, approving the current rider for vegetation management and system hardening.

(8) Joint Stipulations and Settlement Agreements.

<u>Procedural History</u>

On June 17, 2014, a Joint Stipulation and Settlement Agreement (Joint Stipulation 1) was filed. Signatures included, PSO, PUD, OIEC, and QSC. On June 20, Walmart joined the Stipulation. The AG executed Joint Stipulation 1 on July 9, 2014. On July 9, 2014, a Second Joint Stipulation and Settlement Agreement (Joint Stipulation 2) was filed. Joint Stipulation 2 was executed by the AG, PSO and OIEC.

Joint Stipulation 1 was the "settlement of all issues in this proceeding between the parties to this Joint Stipulation." (PSO, PUD, AG, OIEC, QSC, Walmart.) Joint Stipulation 2 was a supplement to Joint Stipulation 1 and was characterized as a "reasonable settlement of these issues". Therefore, AG, PSO and OIEC added additional issues for their settlement.

AARP and Mr. Esposito did not sign either document and AARP actively opposed the approval of the settlements.

Evidence and Positions

PSO

Mr. Sartin explained the process leading to Joint Stipulation 1. The Procedural Schedule in this cause established a settlement conference on May 15. The parties first met as a group on this date and then multiple times thereafter. All parties were provided notice of each of the group negotiations that occurred. In addition, PSO had individual discussions with some of the parties to better understand their views and try to provide as comprehensive of a settlement for as many parties as possible. On June 17, an executed agreement was filed. (Sartin Supplemental Testimony in Support of Joint Stipulation, (Supplemental Testimony) p. 4, LL 20-23, p. 5, LL 1-2.)

While the substance of settlement negotiations is confidential, it is important to note that the negotiations were arms-length discussions among experienced parties. The discussions examined and addressed the various positions advanced by the parties in their filed testimonies and/or statements of position, and they were a collective balance of diverse, well-represented interests. Despite PSO's and Stipulating Parties' efforts, not all parties endorsed the Agreement. (Sartin Supplemental Testimony, p. 5, LL 3-8.)

The Stipulating Parties represented all customer classes and a diverse group of interests with significant and substantially opposing and conflicting positions. The PUD represented all customer classes. QSC represented individual residential customers, commercial customers, trade associations, and cities and towns. Walmart represented commercial customers and small industrial customers. OIEC represented industrial customers. PSO represented all customer classes, as well as its shareholders and employees. (Sartin Supplemental Testimony, p. 5, LL 15-20.) The residential customer class as a whole was represented in this Cause by three of the Stipulating Parties: the PUD, PSO, and AG. (Sartin Supplemental Testimony, p. 6, LL 1-2 (reference refers to PUD and PSO))

Mr. Sartin testified that the Stipulation provided for the following:

PSO has complied with the provisions of Order No. 591185 in Cause No. PUD 201100106 in filing this rate case, and in determining that the Southwest Power Pool Transmission Cost Tariff should be extended until further order of the Commission. It also modifies that tariff so demand-metered customers taking service from PSO's SL1, SL2, and SL3 tariffs are charged on a demand basis.

PSO's current retail operating base revenues are $537,719,075, and PSO has provided tariffs designed to produce these revenues. PSO's rate base of $1,908,675,876, which reflects a six-month post test year level, is used and useful. The effective date of new rates is the first billing cycle of November 2014, which will include an overall impact on total customers' rates of 2.05 percent, and an increase for the total average residential class of $3.11 per month, which is a 3.82 percent change. The changes to other customer classes are provided in Attachment D of the Stipulation.

Although having no impact on overall customer rates, the following fuel-related provisions were part of the stipulation: the removal of the 3.4 cents per kilowatt-hour of fuel costs included in base revenues to the FAC, the moving of $4.8 million of fuel costs currently in base revenues to the FAC; no change in the existing off-system sales sharing between customers and PSO and requiring costs currently recovered under the Base Load Purchase Power Rider (BLPP) and the Purchased Power Capacity Rider (PPC) to be moved to the FAC, and the BLPP and PPC riders be eliminated. (Supplemental Testimony, p. 7, LL 5-23.)

Mr. Sartin testified that the Joint Stipulation creates an AMI Tariff, and provides the basis for its annual determination beginning with the first billing cycle of November 2014, which recovers the first 14 months of AMI costs initially, followed by annual redeterminations thereafter. The AMI provisions also included guaranteed savings of $11 million for labor, vehicles, and overheads during the first four years (Sartin Supplemental Testimony, p. 8, LL 1-11); AMI investment at January 31, 2014, of $16,020,263, is used and useful; and future levels of AMI investment may be found used and useful by the Commission in future regulatory proceedings. A regulatory asset for non-AMI meters is established as they are replaced by AMI meters, with cost recovery of non-AMI meters using a 9.58 percent depreciation rate. The use of over-/under-accounting for regulatory assets and liabilities associated with the difference between actual AMI revenue requirements and actual AMI revenue collected under the AMI Tariff was part of the Joint Stipulation with the return on AMI assets at the authorized return. Additionally, PSO will provide free Home Energy Reports for any requesting customer with an AMI meter.

An authorized return on rate base of 7.63 percent and the return on common stock equity is 9.85 percent for the purposes of calculations of Allowance for Funds Used During Construction and factoring, and for the riders with an equity component.

According to Mr. Sartin, PSO's existing depreciation rates do not change, except for those associated with AMI investments and existing meters. (Sartin Supplemental Testimony, p. 8, LL 12-29.)

PSO's rate case expenses and PUD expert costs paid by PSO are amortized to expense over a two-year period and PSO operation and maintenance storm expenses from prior storms are recovered over a four-year period, and included in rate base.

PSO's interim Standby and Supplemental Service Tariff is made final; and PSO's Residential Service Base Service Charge is increased to $20 per month, offset in total by decreases to residential per kilowatt-hour charges. (Sartin Supplemental Testimony, p. 9, LL 1-7.)

Mr. Sartin testified that from an overall perspective, the significant benefits of the Stipulation were that it:

1. kept in place the current level of overall rates;

2. provides an AMI Tariff which permits expansion of this technology and the attendant substantial benefits to all PSO customers;

3. kept in place current depreciation rates, except for changes to AMI investment and existing meters rates;

4. results in a reasonable allocation of costs and revenues among customer classes;

5. resolves all issues without significantly adding to rate case expense;

6. includes a four-year amortization of $18 million operation and maintenance storm expenses without an increase in rates; and

7. adds certainty to uncertain litigated outcomes for each of the Stipulating Parties. (Sartin Supplemental Testimony, p. 10, LL 7-17.)

According to Mr. Sartin, after a thorough examination of the issues, Stipulating Parties agreed that the Joint Stipulation 1 presents a reasonable resolution of the issues detailed therein, which are interdependent, based on substantial give and take, and which Stipulating Parties believe is in the public interest. (Sartin Supplemental Testimony, p. 13, LL 10-13.)

Ms. Jackson addressed Joint Stipulation Attachments A, B, C, D, E and F.

Attachment A is the SPPTC Tariff and has been modified by Joint Stipulation 1 to allow demand-based billing for industrial customers taking service under the Large Power and Light 1-3 (LPL1-3) rate schedules. (Jackson Supplemental Testimony, p. 4, LL 3-13.)

Attachment B is the AMI Tariff and is designed to recover the revenue requirement associated with PSO's AMI deployment and is applied on a per-meter basis. According to Ms. Jackson, the total average residential class impact is $3.11 per month for the first 14 months, which is a 3.82 percent change. Because the Joint Stipulation results in no other change to PSO's overall rates, the increase from the AMI Tariff represents the overall impact on residential customers. Further, Attachment C shows the allocation of the AMI revenue requirement to the rate classes receiving AMI services based on Joint Stipulation 1. (Jackson Supplemental Testimony, p. 4, LL 15-16, p. 5, LL 1-11.)

Attachment D sets forth the retail revenue distribution based on the provisions of the Joint Stipulation. The revenue distribution is the rate design mechanism by which the change in revenue requirement is assigned to the classes of customers. (Jackson Supplemental Testimony, P. 5, LL 13-15.)

Ms. Jackson testified that Joint Stipulation 1 removes $4.8 million of costs from base rates to be recovered through the FAC. Removing $4.8 million from base rates results in a 0.88 percent reduction to adjusted test year retail base rate revenues. Attachment D of Joint

Stipulation 1 applies the 0.88 percent base rate reduction to all classes equally. Attachment D also depicts the base revenue change for each rate class. (Jackson Supplemental Testimony, p. 6, LL 1-6.)

According to Ms. Jackson, the following table shows the major class base rate and total bill percentage changes based on the provisions of Joint Stipulation 1. (Jackson Supplemental Testimony, p. 6, LL 15-21.)

Major Class	Base Rate % Change Based on Joint Stipulation	Total % Change Based on Joint Stipulation
Residential	-0.88%	3.82%
Commercial	-0.88%	0.97%
Lighting	-0.88%	0.00%
SL 3	-0.88%	0.03%
SL 2	-0.88%	0.00%
SL 1	-0.88%	0.00%
Total Retail	-0.88%	2.05%

Joint Stipulation 1 proposes to increase the base service charge for the Residential Service (RS), Residential Service Time-of-Day (RS TOD), and Variable Peak Pricing (VPP) rate schedules from the current level of $16.16 to $20.00. (Jackson Supplemental Testimony, p. 7, LL 17-19.)

PSO currently has a base service charge and variable kWh rates to recover the total revenue requirement for the residential class. The current base service charge includes customer-related charges such as metering, meter reading, customer services and billing, but it also includes an additional amount related to the distribution demand function revenue requirement represented on a per-customer basis. The distribution demand function contains the costs for such distribution assets as poles, towers, fixtures, overhead and underground conductors, and line transformers. As part of the rate design change, the energy rates were decreased from the current per-kWh rates to account for the additional movement of fixed distribution costs from the variable energy charge to the fixed base service charge. For a typical residential customer, this rate design adjustment alone (not including the AMI tariff charge) results in no change to the base bill. The Commission has previously approved PSO's methodology of inclusion of distribution demand costs, in addition to the distribution customer-related unit cost, in the residential base service charge. The residential class energy rates also reflect the movement of base fuel-related costs from base rate recovery to recovery through the FA rider. The residential rate schedules are found in attached F to Joint Stipulation 1. (Jackson Supplemental Testimony, p. 7, LL 20-23, p. 8, LL 1-13.)

Attachment E is the Standby and Supplemental Tariff supported by Joint Stipulation 1. Currently, the Tariff is available on an interim basis and limited to independent power producers who were previously taking service under PSO's Real Time Pricing Tariff. Joint Stipulation 1 recommends that this tariff be made available on a permanent basis to any qualifying customer.

Attachment F contains the rate schedules for the residential and LUGS rate changes to the base service charge. The residential service tariff sheets also include language stating that home energy reports are available upon request for any customers with AMI meters. (Jackson Supplemental Testimony, p. 9, LL 2-6 and LL 8-13.)

<u>PUD</u>

Mr. Robert Thompson testified on behalf of PUD in support of Joint Stipulation 1. It was Mr. Thompson's opinion that PSO had complied with Order No. 591185 issued in Case No. PUD 201100106 in filing this rate case. (Thompson Testimony in Support of Joint Stipulation p. 4, LL 3-9.)

Mr. Thompson testified that the Stipulating Parties agreed that the Oklahoma Retail Base Rate Non-Fuel Revenue Requirement is $537,719,075 based upon the test year billing units reflected in Section M of the Company's Application Package filed in this proceeding on January 17, 2014.

The Stipulating Parties agreed that the rates produced by the revenue allocation are fair, just, and reasonable and requested that the Commission make such a finding in its Final Order in this Cause.

The Stipulating Parties agreed that the effective date of new rates will be the first billing cycle of November 2014. (Thompson Testimony in Support of Joint Stipulation 1, p. 4, LL 17-18, p. 5, LL 1-8.)

The ROE of 9.85 percent will also apply to the Allowance for Funds Used During Construction (AFUDC), factoring, and for riders with an equity return component that are currently in effect. Applying a ROE of 9.85 percent to PSO's capital structure results in an overall rate of return (ROR) of 7.63 percent. (Thompson Testimony in Support of Joint Stipulation, p.5, LL 14-18.)

These Stipulating Parties agreed to a rate base of $1,908,675,876, which reflected a six-month post test year level. The Stipulating Parties agreed that PSO's base rates approved in this cause should not include 3.4 cents per kWH of embedded fuel that will be moved out of base rates to be recovered through PSO's FAC beginning with the date new rates go into effect. (Thompson Testimony in Support of Joint Stipulation, p. 6, LL 2-3, LL 6-7.)

The Stipulating Parties request the Commission to issue an order approving the AMI Tariff and AMI revenue requirement. The initial AMI Tariff factors will be in place for 14 months beginning with the first billing cycle of November 2014 and ending with the last billing cycle of December 2015; thereafter, subsequent factors will be in place on a 12-month basis.

PSO guarantees $11 million in savings associated with labor, vehicles, and overheads during the first four years of the AMI implementation plan. Five million dollars will be used to reduce the AMI Tariff in years one through three with an additional $6 million reduction in year four for a total of $11 million. The annual $6 million savings will continue in the rider until AMI savings are included in PSO's base rates, which PSO will include in its first base rate case subsequent to the full deployment of AMI. (Thompson Testimony in Support of Joint Stipulation, p. 7, LL 6-10, LL 13-19.)

Mr. Thompson testified that as existing non-AMI meters are replaced by AMI meters, PSO shall establish a regulatory asset for the unrecovered net book value of the non-AMI meters. The non-AMI meter regulatory asset will be amortized using the 9.58 percent depreciation rate approved for existing meters in this proceeding. The regulatory asset net of accumulated amortization will be included in rate base in future base rate cases.

The return on AMI assets being recovered through the AMI Tariff is the cost of capital approved in this proceeding of 7.63 percent. The return will be updated when the OCC approves new values for PSO. (Thompson Testimony in Support of Joint Stipulation, p. 8, LL 3-7, LL 18-20.)

Mr. Thompson testified that the Stipulating Parties agreed that storm restoration operating and maintenance expenses associated with three major storms that occurred in July 2013 (one storm) and December 2013 (two storms) are recoverable expenses, and included in rate base. PSO will recover through base rates $18.5 million of storm costs over a four-year period. (Thompson Testimony in Support of Joint Stipulation, p. 9, LL 12-16.)

Joint Stipulation 1 increases the residential service charge from the existing $16.16 a month to $20.00 a month. The base service charge was increased to $20.00 from the current $16.16 to account for fixed customer, meter, meter reading, and billing costs plus a portion of distribution function costs that are fixed in nature. The first-step energy rates were decreased to account for the additional movement of fixed distribution costs from the energy charge to the base service charge. (Thompson Testimony in Support of Joint Stipulation, p. 10, LL 12-18.)

Mr. Thompson testified that the settlement negotiations were a robust exchange of ideas and many creative solutions were found. The result was what PUD believes is a balanced and fair stipulation that is before the Commission. (Thompson Testimony in Support of Joint Stipulation, p. 12, LL 3-6.)

<u>AG</u>

Mr. Edwin C. Farrar pre-filed Supplemental Testimony in Support of the Second Joint Stipulation and Settlement Agreement on behalf of the Attorney General of the State of Oklahoma.

Mr. Farrar testified that the Second Joint Stipulation and Settlement Agreement is supplemental to the initial Joint Stipulation and Settlement Agreement. The Second Joint Stipulation and Settlement Agreement adds a requirement for PSO to comply with the Electric Usage Data Protection Act ("the Act") and provides specific reporting requirements for the AMI program. Mr. Farrar explained that the Act establishes standards to govern the access and use of customer usage data. Mr. Farrar further testified that PSO had agreed under the Second Joint Stipulation and Settlement Agreement to provide information related to the number of meters installed, customer communication and information programs, customer participation rates, automated connects and disconnects, program cost information, customer complaints and percent of AMI meters read, and demand and energy savings by program. (Farrar Summary of Supplemental Testimony in Support of Second Joint Stipulation, p. 1, LL 1-14.)

AARP

AARP gave oral testimony in opposition to the Joint Settlement. Because all of the contested issues were the same subject matter covered by a portion of Joint Stipulation 1, it is not surprising that AARP's oral testimony covered the same topics as Ms. Alexander's Responsive, Rebuttal and Supplemental Responsive testimonies filed in this cause. Ms. Alexander opposed Joint Settlement 1 because it approved the use of a rider to recover AMI deployment costs; (Tr. 7-21, sd 191, LL 17-20.) had the vegetation reliability rider; (Tr. 7-21, sd 191, LL 20-24.) and there was no low-income program. (Tr. 7-21, sd 191, LL 25.)

Ms. Alexander acknowledged she had addressed the AMI issues and the settlement issues in her written testimony. (Tr. 7-21, sd 195 LL 15-18; sd 197, LL 9-15; sd 197, LL 16-19.)

Since AARP has acknowledged its written testimony addresses their concerns regarding Joint Stipulation 1, there is no need to address these points again.

AARP opposed Joint Stipulation 2 reporting requirements because in the opinion of Ms. Alexander there are "significant defects in the list, mostly by omission." (Tr. 7-21, sd 198, LL 5-7.)

Position of Parties

Joe Esposito

Mr. Powers stated Mr. Esposito had not and was not going to Support the Stipulation. (Tr. 7-22, lw 102, LL 10-25.) No evidence was presented by this party for consideration by the ALJ. The party did not submit a filed Statement of Position, however, the party did submit public comment. [See also Attachment 6]

OIEC

OIEC stated that the settlement responded to OIEC's issues that they raised in the proceeding. The settlement did not address all the issues OIEC raised in the manner in which they recommended but a settlement is a compromise and OIEC believed that it is a good and fair settlement. (Tr. 7-22, lw 103 LL 25- lw 104 LL 7)

OIEC supported both settlements. (Tr. 7-22, lw 103, LL -21-24.) In response to a question from the bench on how the rollout of AMI would impact OIEC's members, Mr. Schroedter responded that OIEC had members it served at Service Levels 1, 2 and 3. Service Level 1 and 2 customers already had automated meters. Service level three members will bear some costs of the AMI rollout. (Tr. 7-22, lw 104, LL 9-21.)

OIEC supported the rollout based upon the testimony setting forth both the qualitative and quantitative benefits. (Tr. 7-22, lw 104, LL 22-25.)

QSC

QSC stated " . . . what has been overlooked in the testimony that has been presented over the last two days is that in fact there are other things that are involved in the Stipulation that benefit customers. The principal thing is that PSO is asking for about $37 million of additional rate relief and that number is zero per the Stipulation that we agreed to." (Tr. lw 106 LL24- lw 107 LL5.) QSC further stated that "There were other changes of a similar nature that related to requests that PSO made. The SPP tariff request that they made would have included some additional recovery through that tariff and that was denied. There were positive things as well that were done in dealing with the number of riders that exist under current rates and the consolidating of those riders into the Fuel Adjustment Clause, rather than having them individually collected. So in its totality, as I said, the Settlement Agreement does provide fair, just and reasonable rates for customers from PSO to collect in the future and we support that." (Tr. 7-22, lw 107, LL 11-23.)

QSC believed the Settlement Agreement "was in the best interest of the customers of PSO and PSO itself to agree to the Settlement." (Tr. 7-22, 1w 105, LL 17-18.) The bench asked how the rollout AMI affected the clients of Mr. Paden. (Tr. 7-22, 1w 105, LL 22-24.) Mr. Paden responded as follows:

> It is individual customers of PSO, it is businesses of PSO, it is trade associations that represent a variety of businesses, it is cities and towns. And as I indicated, we think that the installation of AMI – one of my members is the City of Owasso where a pilot project was located. They are already seeing benefits from the installation of the AMI process there. We think those will be duplicated in other communities.
>
> We think individual citizens have and individual customers have the opportunity to utilize the AMI process by installing thermostats, by using the energy reports that are provided, by using the website to better manage their individual usage. And for that reason we think it has benefit to our various members and both businesses and individuals. (Tr. 7-22, p. 1w 106, LL 1-15.) "

When asked by the bench if the "Stipulation really makes the case just turn on the roll out of an AMI infrastructure" (Tr. 7-22, 1w-106, LL 20-22.) Mr. Paden responded that there are other things that were involved in the Stipulation that benefit customers. (Tr. 7-22, 1w 107, LL 1-2.) The $37 million rate increase went to zero. (Tr. 7-20, 1w 107, LL 3-5.) The changes in the SPPTC tariff request were denied. (Tr. 7-22, 1w 107, LL 12-14.) Various riders were consolidated into the Fuel Adjustment Clause. (Tr. 7-22, 1w 107, LL 15-19.) In the opinion of QSC, "the Settlement Agreement does provide fair, just and reasonable rates for customers from PSO to collect in the future and we support that." (Tr. 7-22, 1w 107, LL 20-23.)

Walmart

Walmart and Sam's were signatories to the First Stipulation and did not oppose the Second Stipulation. (Tr. 7-22, 1w 108, LL 14-17.) Mr. Chamberlain indicated his clients would be paying part of the costs of the AMI rollout. (Tr. 7-22, lw 109, LL 6-8.)

AG

The AG stated that the parties did a fair evaluation of the case and "all the intervenors and PSO, I think, came off of their original positions quite a bit to end up with the first Joint Stipulation and Settlement Agreement." (Tr. 7-22, lw 110, LL 1-6.)

Mr. Sanger, on behalf of the Office of Attorney General, commended all of the Intervenors who signed the first Joint Stipulation for the efforts they made in settling the case. (Tr. 7-22, 1w 110, LL 6-9.)

The AG had some data protection and reporting issues that were resolved with the Second Stipulation. (Tr. 7-22, 1w 110, LL 12-14.) The AG believed "the first Joint Settlement Agreement, as supplemented by the Second Joint Settlement Agreement is fair, just and reasonable." (Tr. 7-22, 1w 111, LL 9-11.)

Mr. Sanger stated that the Attorney General wanted to make sure that the information was available " to confirm that the claims that were being made by PSO were actually supported by data." (Tr.7-22, lw 110, LL. 13-16.) The AG further stated that "all the parties agreed that this is going to change over the next few years, that the Commission and all the intervenors are going to have the opportunity to review data as it comes in. Each year we're going to look at how the program is moving forward and make evaluations as to whether or not it is performing as expected." (Tr 7-22, lw 111, LL 2-7.)

IV. Recommendations to the Commission

"The law and public policy favor settlements and compromises, entered into fairly and in good faith between competent persons, as a discouragement to litigation ...." *Whitehorse v. Johnson* 156 P. 3d 41, 2007 OK 11 at p. 46. Seven out of nine parties endorsed Joint Stipulation 1.

Even though seven out of the nine parties endorsed Joint Stipulation 1, as stated above, the ALJ believes the law requires that the reasonableness of Joint Stipulation 1 must be supported by substantial evidence. *State ex rel. Henry v. Southwestern Bell Telephone Co.*, 825 P. 2d 1305, 1991 OK 134.

Although a majority of the hearing on the merits discussed the deployment of AMI, Joint Stipulation 1 represents "...the parties compromise and settlement *of all issues* in the proceeding...." (Emphasis supplied.) This case was filed pursuant to this Commission's rules found at OAC 165:70 et. Seq. which contain the Minimum Filing Requirements for general base rate cases. OAC 165:70-5-4(d) (2) requires "...the application and testimony of witnesses supporting all exhibits, schedules and other documents contained in the application package." For a general rate case written pre-filed testimony is required for issues that include accounting, cost of service, rate design and revenue distribution, and revenue requirement. Consequently, despite the focus on AMI, this case involves return on equity, depreciation, payroll taxes, incentive compensation, service company costs, pre-paid pension asset, investment to be included in rate base, the proper allocation of transmission costs, class revenue responsibility, and many other issues such as expansion of the SPPTC Tariff. Therefore, the entire record must be examined to review the many issues which make up Joint Stipulation 1.

This totality of issues was addressed by Mr. Sartin's Supplemental Testimony In Support of Joint Stipulation and Settlement Agreement (P. 10) and in Mr. Sartin's testimony at the hearing. (Tr. 7-22, 1w 82, LL 10-25, 1w 83, LL 1-8.) PSO dropped its request for a $37 million rate increase. (Tr. 7-22, 1w 82, LL 19-22.) PSO agreed to a lower ROE from its requested ROE of 10.5. (Tr. 7-22, lw 83, LL 4-8.) PSO dropped its request to amend the SPPTC Tariff. (Tr. 7-22, lw 82, LL 23-25, lw 83, LL 1-3.) In exchange for these and other concessions made with the AG, OIEC, PUD, QSC, and Walmart, the parties agreed to Joint Stipulation 1 which, among other things, approves the AMI rider and the increased base service fee, and importantly results in no change to base rates.

The evidence in opposition to Joint Stipulations 1 and 2 was solely presented by AARP. The ALJ's findings do not adopt AARP's positions. The ALJ recommends that the Commission order adopt the findings of the ALJ as set forth above.

The ALJ further recommends based upon the entire record that the Commission issue an Order approving Joint Stipulation 1 as being fair, just and reasonable and in the public interest.

The ALJ notes that Mr. Sartin made clear that PSO was not asking for pre-approval of AMI costs. (Tr. 7-22, 1w 79 LL 15-18, lw 98, LL 8-11.) PSO further recognized that having an AMI rider did not change the Commission's authority to review in a subsequent rate case the prudence of the AMI investment. (Tr. 7-22, lw 79, LL 19-24.) PSO was seeking a determination that the existing AMI meters in place were used and useful, but not AMI meters installed in the future. (Tr. 7-22, lw 96, LL 18-24; lw 98, LL 4-7.)

Accordingly, the ALJ recommends that the Commission find in its order that PSO has not asked, and the Commission is not granting, pre-approval of the expenditures for the AMI implementation that occur after January 31, 2014.

The ALJ further recommends that the Commission find in its order that it is only finding the investment contained within the rate base determined in this case as being used and useful and that the determination of used and useful status for any future investment in plant will be made in PSO's future rate proceedings.

The ALJ recommends that the Commission issue an Order approving Joint Stipulation 2 which requires tracking and reporting of certain data from the AMI rollout. This will aid all interested parties in monitoring and evaluating the performance of the program.

The ALJ further recommends that the Commission issue an order finding that PSO has complied with Order No. 591185 issued in Cause No. PUD 201100106 and that the Commission issue a final order in Cause No. PUD 201100106 closing the cause.

October 24, 2014
Date

Jacqueline T. Miller
Jacqueline T. Miller
Administrative Law Judge

Attachment "1"

FILED
JUN 17 2014
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA)	CAUSE NO.PUD 201300217

JOINT STIPULATION AND SETTLEMENT AGREEMENT

COME NOW the undersigned parties to the above entitled cause and present the following Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the review and approval of the Oklahoma Corporation Commission ("Commission") as the parties' compromise and settlement of all issues in this proceeding between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

TERMS OF THE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Effective with the final order of the Commission approving all elements of this Joint Stipulation:

1. Order No. 591185 of Cause No. PUD 201100106.

(a) On November 18, 2011, this Commission issued Order No. 591185 in Cause No. PUD 201100106 ("Order"). The Order approved the Southwest Power Pool Transmission Cost Tariff ("SPPTCT") that authorized PSO to recover the Projected Schedule 11 Base Plan Expense of the Southwest Power Pool ("SPP") associated with projects constructed by non-PSO or AEP affiliated transmission owners within SPP, excluding costs of projects constructed by AEP affiliates other than SWEPCO or, if applicable, Southwest Transmission Company. The Order also required PSO to file a base rate case no later than January 18, 2014, to enable the Commission to determine whether the SPPTCT should be amended, extended or terminated and to conduct a review of the SPPTCT.

(b) The Stipulating Parties request the Commission to issue an order finding that PSO has complied with the requirements of Order No. 591185 issued in PUD No. 201100106.

(c) The Stipulating Parties further request the Commission to issue an order finding that the SPPTCT shall be extended until further order of the Commission and that the tariff be modified so that demand-metered customers taking service from PSO's SL1, SL2, and SL3 tariffs will be charged on a demand basis as reflected in Attachment A.

2. Revenue Requirement.

(a) The Stipulating Parties request the Commission to issue an order that PSO shall file tariffs designed to produce Oklahoma jurisdictional operating base revenues of $537,719,075.

(b) The Stipulating Parties request the Commission to issue an order that the agreed-to rate base of $1,908,675,876, which reflects a six month post-test year level, is used and useful.

(c) The Stipulating Parties agree that the effective date of new rates will be the first billing cycle of November 2014.

3. Fuel-related Provisions.

(a) The Stipulating Parties agree that PSO's base rates approved in this cause will remove the 3.4 cents per kWh of embedded fuel and such removal is reflected in the Oklahoma jurisdictional operating base revenues in 2(a) above.

(b) The Stipulating Parties agree that all fuel costs will be recovered through the Fuel Adjustment Clause (FAC). Previously, certain fuel costs (e.g. coal handling) were recovered through base rates. The amount transferred in this proceeding from base rates to the FAC is $4.8 million and is reflected in the Oklahoma jurisdictional operating base revenues in 2(a) above. The amount included in the FAC going forward will be the actual amount of fuel-related expense incurred by PSO.

(c) The Stipulating Parties agree to retain the existing off-system sales sharing between customers and PSO, and that PSO's next base rate case is the next opportunity for a review of the sharing.

(d) The costs being recovered through the Base Load Purchased Power Rider (BLPP) and the Purchased Power Capacity Rider (PPC) will be transferred to and recovered by the FAC. Thus, the BLPP and PPC tariffs will be eliminated going forward and the FAC tariff expanded to recover these additional costs. The method of allocating costs does not change with this transfer between tariffs.

4. Advanced Metering Infrastructure (AMI).

(a) The Stipulating Parties request the Commission to issue an order approving the Advanced Metering Infrastructure (AMI) Tariff (Attachment B) and determining the AMI revenue requirement as set forth in Attachment C. The initial AMI Tariff factors will be in place for fourteen months beginning with the first billing cycle of November 2014 and ending with the last billing cycle of December 2015; thereafter, subsequent factors will be in place on a twelve-month basis.

(b) PSO guarantees $11 million in savings associated with labor, vehicles, and overheads during the first four years of the AMI implementation plan. Five million dollars will be used to reduce the AMI Tariff in years one through three with an additional $6 million reduction in year four for a total of $11 million. The annual $6 million savings will continue until AMI is included in PSO's base rates, which PSO will include in its first base rate case subsequent to the full deployment of AMI.

(c) The AMI investment at January 31, 2014, of $16,020,263 is found to be used and useful. Future levels of AMI investment may be found used and useful by the Commission after review and approval by the Commission in future regulatory proceedings.

(d) As existing non-AMI meters are replaced by AMI meters, PSO shall establish a regulatory asset for the unrecovered net book value of the non-AMI meters. The non-AMI meter regulatory asset will be amortized using the 9.58% depreciation rate approved for existing meters in this proceeding. The regulatory asset net of accumulated amortization will be included in rate base in future base rate cases.

(e) PSO will utilize over/under accounting and record as a regulatory asset or regulatory liability the difference between actual AMI revenue requirements and actual AMI revenues collected under the AMI Tariff. The beginning regulatory asset/liability balance will be the ending regulatory asset/liability balance associated with the AMI pilot programs for the month immediately preceding the effective date of the AMI Tariff. This beginning over/under balance relates to the $2 million annual amount provided in base rates for AMI activities from Cause No. PUD 200800144 and PUD 201000050.

(f) The return on AMI assets being recovered through the AMI Tariff is the cost of capital approved in this proceeding of 7.63 percent. The return will be updated when the OCC approves new values for PSO.

(g) PSO agrees to provide Home Energy Reports for any requesting customer with an AMI meter.

5. Miscellaneous Provisions.

(a) The Stipulating Parties request the Commission to authorize a return on rate base of 7.63 percent.

(b) The Stipulating Parties agree that with the implementation of new rates established in this Cause, the return on common equity rate used only in the formula to calculate Allowance for Funds During Construction ("AFUDC"), factoring, and for riders with an equity return component, shall be 9.85 percent.

(c) The Stipulating Parties agree that PSO's existing depreciation rates approved in PUD 200800144 will not change, except for AMI investments and existing meters, and will continue until such time that the Commission approves new depreciation rates. The only depreciation rate changes will be: 9.58% for existing meters, 6.84% for AMI meters, and 6.67% AMI Network.

(d) The Stipulating Parties request the Commission to allow PSO to recover as a regulatory asset $1,758,728 of rate case expense amortized over two years. The $1,758,728 is comprised of $1,267,094 related to Public Utility Division retained experts paid by PSO from Cause Nos. PUD 201200054 and PUD 201300188 and PSO's integrated resource plan; and $740,000 of estimated rate case expenses associated with this proceeding, offset by $248,367 associated with the true-up of amounts from the prior case (Cause No. PUD 201000050). These are reasonable expenses to be recovered through base rates over a two-year period beginning with the effective date of new rates in this Cause. Actual costs above or below the $740,000 of estimated rate case expense for this Docket will be deferred as a regulatory asset or regulatory liability and addressed in a future proceeding.

(e) The Stipulating Parties agree that storm restoration operation and maintenance expenses associated with three major storms that occurred in July 2013 (one storm), and December 2013 (two storms) are recoverable expenses, and included in rate base. PSO will recover through base rates the $18.5 million of storm costs over a four-year period beginning with the effective date of new rates in this Cause.

6. Rate Design.

(a) The Stipulating Parties agree the revenue distribution should be as set forth in Attachment D to this Joint Stipulation.

(b) The Stipulating Parties request that the Commission issue an order adopting the Standby/Supplemental Tariff, Attachment E.

(c) The Stipulating Parties request the Commission to issue an Order approving the red-lined changes to the tariffs contained in Attachment F to this Joint Stipulation, as well as the proposed language changes found in PSO's filed Section N.

7. Discovery and Motions.

As between and among the Stipulating Parties, all pending requests for discovery and all motions pending before either the Commission or the Administrative Law Judge are hereby withdrawn.

8. General Reservations.

The Stipulating Parties represent and agree that, except as specifically otherwise provided herein:

(a) This Joint Stipulation represents a negotiated settlement for the purpose of compromising and settling all issues which were raised relating to this proceeding.

(b) Each of the undersigned counsel of record affirmatively represents that he or she has full authority to execute this Joint Stipulation on behalf of his or her client(s).

(c) None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation nor shall any of the Stipulating Parties be prejudiced or bound by the terms of this Joint Stipulation should any appeal of a Commission order adopting this Joint Stipulation be filed with the Oklahoma Supreme Court.

(d) Nothing contained herein shall constitute an admission by any party that any allegation or contention in these proceedings as to any of the foregoing matters is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this rate proceeding.

(e) The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, they have entered into this Joint Stipulation to settle among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as a precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its position or testimony in other causes. To the extent there is a difference, the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement, the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

9. Non Severability.

The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore, in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (provided, however, that the affected party or parties may consent to such modification or condition), this Joint Stipulation shall be void and of no force and effect, and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an Order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation and such Order becomes final and non-appealable.

WHEREFORE, the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement of this proceeding with respect to all issues which were raised with respect to this Application, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement.

PUBLIC UTILITY DIVISION
OKLAHOMA CORPORATION COMMISSION

By: Fairo Mitchell
Fairo Mitchell, Energy and Water Policy Director

PUBLIC SERVICE COMPANY OF OKLAHOMA

By: Jack P. Fite
Jack P. Fite
Joann T. Stevenson
Attorney for Public Service Company of Oklahoma

SCOTT PRUITT
ATTORNEY GENERAL OF THE
STATE OF OKLAHOMA

By: ______________________________

Jerry J. Sanger
Assistant Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: ______________________________
Thomas P. Schroedter
Hall, Estill, Hardwick, Gable, Golden & Nelson

QUALITY OF SERVICE COALITION

By: ______________________________
Lee W. Paden

WAL-MART STORES EAST, LP

By: ______________________________
Rick D. Chamberlain

SAM'S EAST, INC.

By: ______________________________
Rick D. Chamberlain

AARP

By: ______________________________
Deborah Thompson

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By: ______________________________
Rick D. Chamberlain

AARP

By: ______________________________
Deborah Thompson

JOE ESPOSITO

By: ______________________________

Don Powers

AVAILABILITY

This Tariff is applicable to and becomes part of each OCC jurisdictional rate schedule and will apply to applicable energy or maximum billing demand consumption of retail customers served at all service levels and to facilities, premises and loads of retail customer.

~~The SPPTC will be implemented the first billing cycle of the month following Commission approval of the SPPTC and shall remain in effect until closed by Commission order. The SPPTC will be reviewed for the purposes of extension, modification or termination during the next PSO base rate case, which will be filed no later than 26 months following the implementation of the SPPTC.~~

This Tariff will include projected Southwest Power Pool (SPP) Base Plan expenses (Schedule 11 of the SPP Open Access Transmission Tariff) incremental to such costs included in PSO's ~~most recent~~ base rate case, PUD Cause No. 201000050, including any credits or refunds. Base plan costs are associated with projects constructed by non-PSO transmission owners within the SPP, excluding costs of projects constructed by Oklahoma Transmission Company, Inc. (OK Transco).

The SPPTC shall be calculated on the customer's bill by multiplying the total billing kilowatt-hours (kWh) for each customer in the residential and commercial major rate class and by maximum billing demand for the industrial major rate classes by the SPPTC Factor for that customer's class for the current month. For service billed under applicable rate schedules for which there is not metering, the monthly kWh usage shall be estimated by the Company and the SPPTC Factor shall be applied to the estimated kWh usage.

The SPPTC Factors shall be determined on an annual basis for each major rate class. The factors shall include the upcoming period's incremental projected SPP Base Plan expenses plus an over or under recovery of actual expenses compared to revenues received under the Tariff for the prior period. ~~The initial SPPTC Factors and the projected SPP Base Plan Expenses to be recovered pursuant to such Factors are attached as Schedule 1 to this Tariff.~~

Method of Calculation for SPPTC Factor:

An SPPTC Factor is calculated annually for each major rate class using the applicable billing determinant, either ~~on a~~ per kWh or per maximum demand ~~basis~~ depending on the major rate class. The formula for the SPPTC Factor is as follows:

SPPTC Factor = (SPP Expenses * Class Transmission Allocator) + True-up
~~kWh~~Applicable Billing Determinant by Major Rate Class

where,

SPP Expenses = Projected Schedule 11 Base Plan Expense of the SPP Open Access Tariff associated with projects constructed by non-PSO or AEP affiliated transmission owners within SPP, excluding costs of projects constructed by AEP affiliates other than SWEPCO or, if applicable, Southwest Transmission Company, incremental to such costs included in PSO's ~~most recent~~ base rate case, PUD Cause No. 201000050, including any credits and refunds allocated to the Oklahoma retail jurisdiction using the ~~most recently~~ approved jurisdictional transmission allocators in PUD Cause No. 201000050.

Class Transmission Allocator = the ~~most recently~~ approved class transmission allocator for each major rate class within the Oklahoma retail jurisdiction from PSO's base rate case in PUD Cause No. 201000050.

True-up = Over or under recovery of the previous period's actual SPP Expenses compared to SPPTC revenues by major rate class.

~~kWh~~Billing Determinant by Major Rate Class = Projected applicable billing determinant for each major class, either kWh or maximum demand sales ~~for each major rate class~~ for the twelve month effective period of the SPPTC Factors.

Annual Re-determination:

Beginning in 2015, and continuing each year thereafter, the Company will submit the re-determined SPPTC factors 11 months following the implementation of the PUD approved SPPTC. Calculations for the re-determined rates shall be made by the application of the SPPTC formula set forth in this tariff. The Company shall provide information sufficient to document and support the reasonableness of the projected SPP Expenses, the True-up amounts during the previous period, and the re-determined SPPTC rates with each annual re-determination. ~~Beginning in September of 2012, and continuing each year thereafter, the Company will file the re-determined SPPTC factors in this Cause (PUD 201100106) for implementation on the first billing cycle of the following October. Calculations for the re-determined rates shall be made by the application of the SPPTC formula set forth in this tariff. The Company shall file information sufficient to document and support the reasonableness of the projected SPP Expenses, the True-up amounts during the previous period, and the re-determined SPPTC rates with each annual re-determination. Following the filing submittal of the re-determined SPPTC factors, the Commission Staff will convene a technical conference where~~ The company shall provide the projected revenue impact of the annual SPP Expense re-determination for each major customer class. The company shall also provide any information or studies regarding the economic benefit or analysis to customers associated with the eligible incremented SPP expenses.

The company will address the reasonableness of SPP Expenses collected through the SPPTC during the next PSO base rate case and in future base rate cases. Based on the review by the Commission Staff and parties in the next base rate case, any over or under recovery of SPP Expenses collected through the SPPTC shall be refunded to or collected from customers with interest calculated at the applicable Commission established interest rate applied to customer deposits for deposits held one year or less, or the interest rate applied to customer deposits held for more than one year.

Should a cumulative over-recovery or under-recovery balance arise during any SPPTC cycle which exceeds ten percent (10%) of the annual SPP Expenses reflected in the current SPPTC, then either the Commission Staff or the Company may propose an interim revision to the currently effective SPPTC rate.

ATTACHMENT B

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SHEET NO. ______
REPLACES SHEET NO. N/A
EFFECTIVE DATE ______

SCHEDULE: ADVANCED METERING INFRASTRUCTURE (AMI) TARIFF

APPLICABILITY

This Tariff is applicable to and becomes part of each OCC jurisdictional rate schedule of retail customers served at secondary and primary service levels. For service under applicable rate schedules for which there is metering, a monthly AMI charge will be estimated and applied.

AMI FACTOR DETERMINATION

An AMI Factor is calculated annually for each customer for which there is metering subject to the applicability of the tariff. The formula for the AMI Factor is as follows:

$$\text{AMI Factor} = \frac{\text{AMI Annual Revenue Requirement} + \text{True-up}}{\text{Meter Count} * 12}$$

where,

AMI Annual Revenue Requirement = the annual class revenue requirement associated with PSO's AMI deployment reflecting the OCC approved rate of return on PSO's AMI investment and the associated costs and savings.

True-up = Over- or under-recovery of the previous annual AMI revenue requirement.

Meter Count = Meter count of customers served under the applicable rate schedules for the most recent twelve month period.

Initial AMI Factors to be effective with the first billing cycle for November 2014 through the last billing cycle for December 2015:

Residential - $3.11 per month

Commercial - $3.88 per month

Industrial (SL3) - $6.71 per month

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SCHEDULE: ADVANCED METERING INFRASTRUCTURE (AMI) TARIFF

TERM

The AMI Tariff will remain in effect until the first base rate case subsequent to the full implementation of AMI. The AMI Tariff will be re-determined annually during the AMI implementation period to reflect the estimated annual revenue requirement and the true-up amount.

PUD 201300217
Settlement Attachment C

PUBLIC SERVICE COMPANY OF OKALHOMA
AMI Revenue Requirement Allocation
For the Billing Cycles Nov-2014 through Dec-2015

	AMI Meters $ Weighted	Allocation	AMI Rev Req Allocation	Test Year End Meter Count	AMI Charge per Month
Residential					
LURS	$ 1,344,596		$ 679,941	15,635	$ 3.11
Residential	$ 38,327,204		$ 19,381,459	445,665	$ 3.11
Total Residential	$ 39,671,800	84.07%	$ 20,061,400	461,300	$ 3.11
Commercial					
LUGS	$ 6,155,047		$ 3,168,300	58,365	$ 3.88
GS	$ 995,675		$ 508,821	9,373	$ 3.88
PL	$ 286,581		$ 83,729	1,542	$ 3.88
MP	$ 7,469		$ 3,854	71	$ 3.88
Total Commercial	$ 7,444,773	15.78%	$ 3,764,703	69,352	$ 3.88
Industrial					
SL3	$ 70,186	0.15%	$ 35,492	378	$ 6.71
Total	$ 47,186,759	100.00%	$ 23,861,595	$ 531,030	$ 3.21

AMI Revenue Requirement

Year 1	$ 7,306,236
Year 2	16,555,359
	$ 23,861,595

PSO
AMI Revenue Requirement

Line No.		YEAR END 2014	2015	2016
1	Utility Plant	37,103,878	92,847,301	132,840,842
2	Reserve for Depreciation	(4,212,339)	(9,093,237)	(18,317,907)
3	Net Utility Plant	32,891,538	83,754,064	114,522,936
4	Accumulated ADIT	(3,620,094)	(7,099,335)	(10,346,225)
5	**Rate Base**	**29,271,445**	**76,654,729**	**104,176,711**
6	Pre Tax Weighted Cost of Capital	10.65%	10.65%	10.65%

		BASED ON MONTH END RATE BASE 2014	2015	2016	3-YR TOTAL
7	***Return on Rate Base + Income Taxes	1,962,080	5,330,967	10,044,891	17,337,939
8	O&M Expense	2,124,172	5,930,204	9,706,669	17,761,045
9	Guaranteed O&M Savings (*)	0	(1,080,755)	(4,006,500)	(5,087,255)
10	Depreciation Expense	2,099,862	4,880,897	9,224,670	16,205,429
11	Severance Amortization	916,667	916,667	916,667	2,750,000
12	Property Taxes	166,315	493,222	1,255,925	1,915,462
13	Factoring Costs	37,140	84,157	138,679	259,975
14	Revenue Requirement	7,306,236	16,555,359	27,281,000	51,142,595

*** Note - Return + Income Tax amounts shown on Line No. 7 are derived from monthly rate base amounts and not the year end rate base amounts shown on Line No. 5.

(*) Note - For 2017, guaranteed savings are $6 million.

PUD 201300217
Settlement Attachment C

PSO
AMI Rider Revenue Requirement

	Account	2014	2015	2016	Total
O&M:					
GridMgt	586	547,172	1,358,954	1,440,869	3,346,995
Incremental MRO	586	-	816,750	1,410,480	2,227,230
Incremental MRO	903	-	272,250	470,160	742,410
Incremental MRO	920	-	272,250	470,160	742,410
MRO Severance	902	916,667	916,667	916,667	2,750,000
Labor Savings	586	0	(648,453)	(2,403,900)	(3,052,353)
Labor Savings	903	0	(216,151)	(801,300)	(1,017,451)
Labor Savings	920	0	(216,151)	(801,300)	(1,017,451)
AMI Network	586	16,351	186,459	245,266	448,076
AMI Network	935	40,649	463,541	609,734	1,113,924
AMI IT	920	337,078	425,011	388,372	1,150,461
AMI IT	923	266,517	336,043	307,073	909,632
AMI IT	935	316,406	398,946	364,554	1,079,906
Consumer Programs	908	600,000	1,400,000	4,000,000	6,000,000
Depreciation Expense	403.7	2,099,862	4,880,897	9,224,670	16,205,429
Factoring Expense	426.5	37,140	84,157	138,679	259,975
Property Tax Expense	408.1	166,315	493,222	1,255,925	1,915,462
Federal Income Tax Expense		475,832	1,292,835	2,436,028	4,204,696
State Income Tax Expense		81,571	221,629	417,605	720,805
Cost of Debt		520,988	1,415,524	2,667,205	4,603,717
Return On Equity		883,688	2,400,980	4,524,053	7,808,721
Revenue Requirement		7,306,236	16,555,359	27,281,000	51,142,595

ATTACHMENT D
Revenue Distribution

Customer Group	Current Non Fuel Revenue w/Spec Contract	Settlement Non-Fuel Revenue w/Spec Contract	Base Revenue Change	Percent Change	Current Special Contract Class Allocation	Settlement Special Contract Allocator	Settlement Service Level 2 Revenue Change	Settlement Special Contract Class Allocation
Residential					$ 3,754,583			
Lurr	2,512,836	2,490,802	($22,034)	-0.86%	17,392	0.00	($153)	$17,239
RS	272,812,822	270,420,634	($2,392,187)	-0.86%	1,888,192	0.50	($16,557)	1,871,635
Total RS	$275,325,658	$272,911,436	($2,414,221)	-0.88%	$1,905,584	0.51	($16,709)	$1,888,874
Commercial								
LUGS	50,283,424	49,842,509	($440,915)	-0.86%	348,022	0.09	($3,052)	$344,970
GS	94,866,290	94,034,445	($831,845)	-0.86%	656,588	0.17	($5,757)	$650,831
PL	37,057,916	36,732,970	($324,946)	-0.86%	256,485	0.07	($2,249)	$254,236
UMS	473,557	469,405	($4,152)	-0.86%	3,278	0.00	($29)	$3,249
MP	307,567	304,870	($2,697)	-0.86%	2,128.73	0.00	($19)	$2,110
Commercial Total	$182,988,755	$181,384,199	($1,604,556)	-0.86%	$1,266,502	0.34	($11,105)	$1,255,396
Lighting								
GSL	14,745	14,616	($129)	-0.88%	102	0.00	($1)	$101
OL	657,035	651,273	($5,761)	-0.86%	4,547	0.00	($40)	$4,506
SL / MR	8,725,216	8,648,710	($76,508)	-0.86%	60,388.87	0.02	($530)	$59,859
MSL	1,604,326	1,590,258	($14,066)	-0.88%	11,104	0.00	($97)	$11,006
TS	66,667	66,102	($585)	-0.88%	462	0.00	($4)	$458
Total Lighting	$11,068,010	$10,970,958	($97,051)	-0.88%	$76,604	0.02	($672)	$75,932
	$9,382,252				$64,935			
Industrial								
SL3 Total	37,518,638	37,189,653	($328,985)	-0.86%	259,674	0.07	($2,277)	$257,397
SL2 Total	29,196,942	28,940,925	($256,016)	-0.88%	202,078	0.06	($1,772)	$200,306
SL1 Total	6,377,827	6,321,902	($55,925)	-0.88%	44,142	0.01	($387)	$43,755
Total Retail	$542,475,838	$537,719,075	($4,756,755)	-0.86%	$3,754,583	1.00	($32,922)	$3,721,661

ATTACHMENT D
Revenue Distribution

Settlement Revenue Change w/Spec Contr	Settlement Revenue Change w/o Spec Contr	Settlement Non Fuel Rev Requirement w/o Spec Contr	Settlement Non Fuel Revenue w/Spec Contr	Settlement Non-Fuel % Increase w/o Spec Contr	Settlement Class Increase	Settlement Non Fuel Rev Requirement w/o Spec Contr	Settlement Non-Fuel % Increase w/o Spec Contr
($22,034)	($21,882)	$2,473,583	$2,490,802	-0.88%	($21,882)	$2,473,583	-0.88%
($2,392,187)	(2,375,630)	268,548,999	270,420,634	-0.88%	($2,375,630)	$268,548,999	-0.88%
($2,414,221)	($2,397,512)	$271,022,582	$272,911,436	-0.88%	($2,397,512)	$271,022,582	-0.88%
($440,916)	($437,864)	$49,497,538	$49,842,509	-0.88%	($437,864)	$49,497,539	-0.88%
($831,845)	($826,087)	$93,383,615	$94,034,448	-0.88%	($826,087)	$93,383,615	-0.88%
($324,946)	($322,697)	$36,476,734	$36,732,970	-0.88%	($322,697)	$36,476,734	-0.88%
($4,152)	($4,124)	466,156	$469,406	-0.88%	($4,124)	$466,156	-0.88%
($2,697)	($2,678)	302,760	$304,870	-0.88%	($2,678)	$302,760	-0.88%
($1,604,556)	($1,593,450)	$180,126,803	$181,384,199	-0.88%	($1,593,450)	$180,126,803	-0.88%
($129)	($128)	$14,515	$14,616	-0.88%	($128)	$14,515	-0.88%
($5,761)	($5,721)	646,766	$651,273	-0.88%	($5,721)	$646,766	-0.88%
($76,508)	($75,978)	6,588,850	$8,848,710	-0.88%	($75,978)	$6,588,850	-0.88%
($14,068)	($13,970)	1,579,251	$1,590,258	-0.88%	($13,970)	$1,579,251	-0.88%
($585)	($581)	65,644	$66,102	-0.88%	($581)	$65,644	-0.88%
($97,051)	($96,379)	$10,895,027	$10,970,959	-0.88%	($96,379)	$10,895,027	-0.88%
($328,988)	($326,709)	$36,932,258	$37,189,653	-0.88%	($326,709)	$36,932,258	-0.88%
($256,016)	($254,244)	28,740,819	$28,940,925	-0.88%	($254,244)	$28,740,819	-0.88%
($55,925)	($55,538)	6,278,147	$6,321,902	-0.88%	($55,538)	$6,278,147	-0.88%
($4,756,755)	($4,723,832)	$533,997,415	$537,719,675	-0.88%	($4,723,832)	$533,997,415	-0.88%

ATTACHMENT D
Revenue Distribution

	Settlement Non Fuel Revenues w/o Spec Contr	——Rate Design—— Settlement Base Revenue Variance w/o Spec Contr	Settlement Non Fuel Revenues w/ Spec Contr	Settlement AMI Rider Revenues	Settlement Present Fuel + Other Revenues	Total Present Revenues	Total Settlement Revenues w/ Spec Contr	Settlement Revenue Difference	Settlement % Difference
	$2,473,482	($81)	$2,490,721	$ 679,041	1,334,993	$3,825,386	$4,505,255	$679,860	17.77%
	268,548,967	(33)	270,420,602	$19,381,459	250,830,268	$521,250,902	540,632,329	19,381,426	3.72%
	$271,022,449	($114)	$272,911,323	$20,061,400	$252,164,861	$525,076,287	$545,137,584	$20,061,286	3.82%
	$49,497,011	($528)	$49,641,991	$ 3,186,300	38,942,873	$88,765,382	$91,853,164	$3,187,772	3.57%
	$93,384,250	$535	$94,035,061	$ 506,821	109,233,877	$203,268,332	$203,777,778	$508,456	0.25%
	$36,476,176	($558)	$36,732,412	$ 83,729	56,975,544	$93,708,514	$93,791,685	$83,171	0.09%
	$468,209	$53	469,458	0	401,536	$870,940	870,994	53	0.01%
	$302,774	$14	304,884	$ 3,854	450,458	$755,327	759,186	3,866	0.51%
	$180,128,420	($383)	$181,183,816	$3,784,703	$206,004,287	$387,368,496	$391,152,806	$3,784,320	0.97%
	$14,613	($2)	$14,614	$0	13,188	$27,804	$27,801	($2)	-0.01%
	$648,748	($18)	651,255	0	830,000	$1,481,273	1,481,255	(18)	0.00%
	$8,568,774	($76)	8,648,634	0	2,792,726	$11,441,436	11,441,359	(76)	0.00%
	$1,579,217	($34)	1,690,223	0	1,959,232	$3,649,490	3,649,455	(34)	0.00%
	$85,603	($42)	86,060	0	38,460	$124,562	124,521	(42)	-0.03%
	$10,894,834	($173)	$10,970,785	$0	$5,653,605	$16,624,564	$16,624,392	($173)	0.00%
	$36,834,050	$1,793	$37,191,447	$ 35,492	70,018,842	$107,206,496	$107,243,781	$37,285	0.03%
	$28,738,835	($1,984)	28,938,941	0	73,548,123	$102,489,046	102,487,064	(1,984)	0.00%
	$6,276,767	$640	6,322,642	0	17,775,381	$24,097,284	24,097,924	640	0.00%
	$553,997,185	($320)	$557,718,886	$23,881,685	$626,163,100	$1,162,862,176	$1,186,743,351	$23,881,375	2.05%

Availability

This schedule is available to Customers who request Standby and/or Supplemental electric service for power production facilities, including renewable energy cogeneration facilities, having a minimum capacity of more than 100 kW and designed to supply all or some of their on-site electricity requirements, which operate in parallel with the Company's system without adversely affecting the operation of equipment and service of the Company and its customers, and without presenting a safety hazard to the Company and customer personnel.

This rate schedule shall not apply to qualified small power producers or co-generators, as defined by the Public Utility Regulatory Policies Act (PURPA) and subsequently Chapter 40 of the Oklahoma Corporation Commission rules, who have a maximum capacity of 100 kW or less.

Service under this schedule requires a contract for electric service with a term of not less than one (1) year and an interconnection agreement that sets forth the terms, conditions and any special equipment required, as specified by the Company, to allow such parallel operation with Company's system.

Service may be taken at Transmission (Service Level 1), Primary Substation (Service Level 2), Primary Service (Service Level 3), or Secondary (Service Level 4 or 5). Service provided under this rate schedule is supplied at one location at one voltage, is considered firm and is not available for resale. The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission.

Standby Service means electric capacity or energy supplied by the Company to replace energy ordinarily generated by Customer's on-site power production facilities when such facilities are unavailable to supply Customer's capacity and energy requirements. The Customer shall contract with the Company for a specific amount of Standby capacity provided that such capacity amount shall not exceed the maximum rating of Customer's power production facilities.

Supplemental Service means electric capacity or energy supplied by the Company and ordinarily required by Customer in excess of the Standby contract capacity amount. The Customer shall contract with the Company for a specific amount of Supplemental capacity. Supplemental service shall be provided according to all the provisions of the Large Power and Light (LPL) rate schedule for Service Levels 1, 2, and 3 or Power and Light Time of Day (PLTOD) or Power and Light (PL) for Service Levels 4 and 5.

Standby Rates

Transmission (Service Level 1)

Standby Service Fee $280.00 per month

Monthly Standby Charge is the greater of:

On Peak period:

Daily Demand Charge $0.21 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $1.96 per monthly contract demand (kW)

Off-Peak period:

Daily Demand Charge $0.09 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $0.84 per monthly contract demand (kW)

Energy Charge All Months $~~0.035766~~0.001685 per kWh

Primary Substation (Service Level 2)

Standby Service Fee $280.00 per month

Monthly Standby Charge is the greater of:

On-Peak period:

Daily Demand Charge $0.28 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $2.55 per monthly contract demand (kW)

Off-Peak period:

Daily Demand Charge $0.12 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $1.09 per monthly contract demand (kW)

Energy Charge All Months $~~0.036120~~0.002025 per kWh

Primary (Service Level 3)

Standby Service Fee $280.00 per month

Monthly Standby Charge is the greater of:

On-Peak period:

Daily Demand Charge $0.39 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $3.52 per monthly contract demand (kW)

Off-Peak period:

Daily Demand Charge $0.17 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $1.51 per monthly contract demand (kW)

Energy Charge All Months $~~0.037023~~0.002869 per kWh

Secondary (Service Levels 4 and 5)

Standby Service Fee $126.15 per month

Monthly Standby Charge is the greater of:

On-Peak period:

Daily Demand Charge $0.57 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $5.20 per monthly contract demand (kW)

Off-Peak period:

Daily Demand Charge $0.24 times the sum of daily maximum demands (kW), or

Minimum Standby Charge $2.23 per monthly contract demand (kW)

Energy Charge All Months $~~0.041300~~0.007084 per kWh

For Customers that only contract for Standby service, any metered demand in excess of the contract amount shall automatically increase the contract amount for Standby to the higher level.

For Customers that contract for both Standby and Supplemental service, any metered demand in excess of the sum of both contract amounts shall be considered to be Supplemental, and the contract Supplemental service capacity shall automatically increase to the higher level.

The daily maximum demand is the maximum metered demand, in kW, delivered each day.

The monthly contract demand is the amount, in kW, of the contracted Standby or Supplemental service capacity.

Metered demand data is based on thirty minute integrated periods measured by a demand meter.

KWh is the maximum metered kWh delivered during the billing period.

The monthly maximum demand and the monthly maximum kVAR requirements will be the highest metered kW and kVAR occurring during the billing period.

The On Peak period is from June 1 through September 30 of each calendar year.

The Off Peak period is from October 1 through May 31 of each calendar year.

General Terms

If the Customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the Customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

Monthly bill shall be subject to adjustments pursuant to the Fuel Cost Adjustment, Tax Adjustment, Metering Adjustment, and all applicable Riders. The minimum monthly bill is the Standby Service Fee plus the demand charges.

Terms of Payment

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 4-1A
REPLACES SHEET NO. 4-1
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE RESIDENTIAL SERVICE (LURS) **RATE CODE 020**

AVAILABILITY

This rate schedule is closed. This rate schedule is only available to customers served at a premise under this rate schedule as of February, 2009. This schedule is available for a residential dwelling unit containing kitchen appliances, permanent sewer or septic facilities, and water service. Separately metered barns, garages, boat docks, or individual hotel or motel rooms are not considered a residence.

This schedule is not available for resale, stand-by, business, manufacturing, or agricultural use. Service will continue to be supplied under this schedule unless a material and permanent change in the customer's load occurs or the customer is no longer eligible as described in the *Special Conditions of Service.*

A written contract may be required at the option of the Company when unusual service conditions exist.

The Company will provide service at one location for the entire electrical requirements of the customer and at a nominal secondary voltage of 120/240 volts single phase unless specifically agreed to otherwise by the Company.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission. For customers with AMI meters, home energy reports are available upon request.

SPECIAL CONDITIONS OF SERVICE

1. Each kilowatt-hour (kWh) step of this schedule shall be multiplied by the number of separate living quarters served through the meter.

2. An existing customer on this rate schedule is eligible for this schedule only if the customer has an average monthly usage of 500 kWh or less during the On-Peak Season. At the end of the On-Peak Season, the average daily kWh usage cannot exceed 16.67 kWh.

3. When a customer exceeds 2,500 kWh in total during the current On-Peak Season, the customer will be moved to the Residential Service schedule. Billing under the Residential Service Schedule will begin with the current month.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
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PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 4-2A
REPLACES SHEET NO. 4-2
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE RESIDENTIAL SERVICE (LURS) **RATE CODE 020**

MONTHLY RATES

Base Service Charge $9.98

Energy Charge

On-Peak Season

~~5.64~~ 2.17¢ per kWh for the first 600 kWh

~~9.70~~ 6.25¢ per kWh for all additional kWh

Off-Peak Season

~~5.64~~ 2.17¢ per kWh for all kWh

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is the Company's billing months of June through October, inclusive. The Off-Peak Season is the Company's billing months of November through May, inclusive.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the *Base Service Charge* of $9.98 per residential unit. The Minimum Monthly Bill will be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
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PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 4-3A
REPLACES SHEET NO. 4-3
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE RESIDENTIAL SERVICE (LURS) RATE CODE 020

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 3 - 1B
REPLACES SHEET NO. 3 - 1A
EFFECTIVE DATE ______

SCHEDULE: RESIDENTIAL SERVICE (RS) — RATE CODE 015 & 038

AVAILABILITY

This rate schedule is available in all service areas for any residential use, including individually metered outbuildings supporting the primary residence, which are located on the site of the primary residence.

This schedule is not available for resale, stand-by, business, manufacturing or agricultural use. Once this schedule is selected, service will continue to be supplied under this schedule for twelve consecutive months unless a material and permanent change in the customer's load occurs.

A written contract may be required at the option of the Company when unusual service conditions exist.

The Company will provide service at one location for the entire electrical requirements of the customer and at a nominal secondary voltage of 120/240 volts single phase unless specifically agreed to otherwise by the Company.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission. For customers with AMI meters, home energy reports are available upon request.

SPECIAL CONDITIONS OF SERVICE (038)

Each kilowatt-hour (kWh) step of this schedule shall be multiplied by the number of separate living quarters served through the meter.

MONTHLY RATES

Base Service Charge $20.00~~16.16~~

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 3 - 2B
REPLACES SHEET NO. 3 - 2A
EFFECTIVE DATE ______

SCHEDULE: RESIDENTIAL SERVICE (RS) RATE CODE 015 & 038

Energy Charge

On-Peak Season

~~6.76~~ 2.891¢ per kWh for the first 1,350 kWh

~~7.71~~ 3.757¢ per kWh for all additional kWh

Off-Peak Season

~~6.38~~ 2.580¢ per kWh for the first 475 kWh

~~5.38~~ 1.710¢ per kWh for the next 775 kWh

~~4.54~~ 1.140¢ per kWh for all additional kWh

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is the Company's billing months of June through October, inclusive. The Off-Peak Season is the Company's billing months of November through May, inclusive.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the Base Service Charge of $20.00~~16.16~~ per residential unit. The minimum bill shall be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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KIND OF SERVICE: ELECTRIC

SCHEDULE: RESIDENTIAL SERVICE (RS) RATE CODE 015 & 038

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rates is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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KIND OF SERVICE: ELECTRIC

SHEET NO. 5-1A
REPLACES SHEET NO. 5-1
EFFECTIVE DATE

SCHEDULE: RESIDENTIAL SERVICE TIME OF DAY ~~PILOT~~ (RSTOD) **RATE CODE 030**

AVAILABILITY

This tariff is limited to ~~100 TOD pilot customers plus~~ gridSMART ~~pilot~~ participants plus an additional 100 customers without an AMI meter. ~~The pilot will be available until the Final Order from the next PSO Oklahoma Corporation Commission rate review occurring after Docket No. 201000050.~~

This rate schedule is available in all service areas for any residential use.

This schedule is not available for resale, stand-by, business, manufacturing or agricultural use. Once this schedule is selected, service will continue to be supplied under this schedule for twelve consecutive months unless a material and permanent change in the customer's load occurs.

A written contract may be required at the option of the Company when unusual service conditions exist.

The Company will provide service at one location for the entire electrical requirements of the customer and at a nominal secondary voltage of 120/240 volts single phase unless specifically agreed to otherwise by the Company.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission. For customers with AMI meters, home energy reports are available upon request.

MONTHLY RATES

Base Service Charge $20.00~~16.16~~

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 5-2A
REPLACES SHEET NO. 5-2
EFFECTIVE DATE _

SCHEDULE: RESIDENTIAL SERVICE TIME OF DAY ~~PILOT~~ (RSTOD) — RATE CODE 030

Energy Charge

On-Peak Season

~~12.44~~ 7.82¢ per kWh for On-peak kWh (hours 2:00 to 7:00, Monday-Friday)

~~5.14~~ 1.71¢ per kWh for all other kWh

Off-Peak Season

~~6.38~~ 2.58¢ per kWh for the first 475 kWh

~~5.388~~ 1.71¢ per kWh for the next 775 kWh

~~4.54~~ 1.14¢ per kWh for all additional kWh

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is the Company's billing months of June through October, inclusive. The On-Peak Hours are 2:00 pm to 7:00 pm, Monday through Friday during the On-Peak Season. The Off-Peak Season is the Company's billing months of November through May, inclusive.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the Base Service Charge of $20.00~~16.16~~ per residential unit. The minimum bill shall be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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KIND OF SERVICE: ELECTRIC

SHEET NO. 5-3A
REPLACES SHEET NO. 5-3
EFFECTIVE DATE

SCHEDULE: RESIDENTIAL SERVICE TIME OF DAY ~~PILOT~~ (RSTOD) RATE CODE 030

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rates is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 52-1
REPLACES SHEET NO. NEW
EFFECTIVE DATE 12/28/11

SCHEDULE: VARIABLE PEAK PRICING RESIDENTIAL SERVICE TARIFF (VPPRS) RATE CODE 036

AVAILABILITY

This rate schedule is available to individual residential customers on a voluntary basis for residential electric service. This rate schedule is limited to gridSMART® tariff participants.

For non-owner occupied dwellings, the Company may require permission from the property owner to install auxiliary communicating equipment. Customers will not be eligible for this schedule if the property owner does not allow installation of auxiliary communicating equipment.

Customers electing to take service under the Variable Peak Pricing Residential Service Tariff are expected to remain on this schedule for a minimum of one (1) year. A written contract may be required at the Company's option. If the customer terminates service under this schedule, the customer will not be eligible to receive service under this schedule for a period of one (1) year from termination date. Customers electing to take service under the VPPRS Tariff are not eligible to take service under the Direct Load Control Tariff schedule.

This schedule is not available for resale, stand-by, business, manufacturing or agricultural use.

The Company will provide service at one location for the entire electrical requirements of the customer and at a nominal secondary voltage of 120/240 volts single phase unless specifically agreed to otherwise by the Company.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission. For customers with AMI meters, home energy reports are available upon request.

~~EQUIPMENT~~

~~The Company will furnish and install, in the customer's presence, a Home Area Network (HAN). If necessary, the Company may also furnish and install auxiliary communicating equipment inside the customer's residence. All equipment will be owned and maintained by the Company until such time as the Variable Peak Pricing Service Tariff is discontinued or the customer requests to be removed from the program after completing the initial mandatory period of one (1) year, at which time, ownership of the HAN will transfer to the customer. Upon request, the HAN and/or auxiliary communicating equipment will be picked up by the Company if the customer terminates service under this schedule within the first year. The customer is not required to pay a deposit for this equipment. However, failure to return the HAN and~~

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P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 52 - 2
REPLACES SHEET NO. NEW
EFFECTIVE DATE 12/28/11

SCHEDULE: VARIABLE PEAK PRICING RESIDENTIAL SERVICE TARIFF (VPPRS) RATE CODE 036

~~auxiliary communicating equipment in good working order may result in additional charges in the amount of the current prevailing cost of the HAN and auxiliary communicating equipment.~~

~~Should the customer lose or damage the HAN and/or auxiliary communicating equipment, the customer will be responsible for the cost of replacing or repairing the device(s). If the device(s) malfunction(s) through no fault of the customer, the Company will replace or repair the device(s) at its expense during the first one (1) year.~~

MONTHLY RATES

Base Service Charge ~~$16.16~~ 20.00

Energy Charge

On-Peak Season

Low Cost Hours	11:00 p.m. – 10:00 a.m.	~~5.00~~ 1.33¢ per kWh
Medium Cost Hours	10:00 a.m. – 2:00 p.m.	~~6.00~~ 2.20¢ per kWh
	7:00 p.m. – 11:00 p.m.	~~6.00~~ 2.20¢ per kWh
High Cost Hours	2:00 p.m. – 7:00 p.m.	~~12.00~~ 7.39¢ per kWh
Critical Peak Hours	When Notified	50.00¢ per kWh

Off-Peak Season

~~6.38~~ 2.58¢	per kWh for the first 475 kWh
~~5.38~~ 1.71¢	per kWh for the next 775 kWh
~~4.54~~ 1.14¢	per kWh for all additional kWh

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 52 - 3
REPLACES SHEET NO. NEW
EFFECTIVE DATE 12/28/11

SCHEDULE: VARIABLE PEAK PRICING RESIDENTIAL SERVICE TARIFF (VPPRS) RATE CODE 036

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is defined as the Company's billing months of June through October, inclusive. The Off-Peak Season is defined as the Company's billing months of November through May, inclusive.

NOTE: Unless a critical peak event is called, all kWh consumed during the summer months on weekends (all hours of the day on Saturdays and Sundays) and the legal holidays, Independence Day and Labor Day, are billed at the low cost level.

CRITICAL PEAK EVENTS

Critical peak events shall be called at the sole discretion of the Company. Critical peak events shall not exceed five (5) hours per day and sixteen (16) events per on peak season. The maximum number of hours during any On-Peak Season that can be designated by the Company as critical peak period hours is 80.

CRITICAL PEAK AND SYSTEM EVENT NOTIFICATIONS

Customers will be notified by the Company by 4:00 p.m. the evening prior to a critical peak event ~~through the in-home display or other enabling technology when it becomes available~~. Receipt of the price notification is the customers' responsibility. The Company has the ability to cancel a scheduled event with at least two (2) hours notice prior to the start of the event due to unforeseen changes in conditions.

In the event of a system emergency, the Company may, with at least two (2) hours notice, designate a system emergency at any time during the year, for a period lasting no less than two (2) hours and no more than five (5) hours. Such emergency events will not count toward the total number of critical peak events, as defined above, that are available during the cooling season.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the Base Service Charge of ~~$16.16~~20.00 per residential unit. The minimum bill shall be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

SPECIAL TERMS AND CONDITIONS

The Company shall collect data during the course of this program. Customer-specific information will be held as confidential and data presented in any analysis will protect the identity of the individual customer.

At the end of an initial one (1) year trial period under the Schedule, the customer will be held harmless from charges in excess of the energy charges they would have incurred under the otherwise applicable service schedule. After the one (1) year trial period, the customer will be required to pay the actual energy charges incurred under this schedule.

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rates is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

Metering Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Metering Adjustment Rider.

Customers are subject to all applicable riders in effect at time service is rendered.

TERMS OF PAYMENT

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 52 - 5
REPLACES SHEET NO. NEW
EFFECTIVE DATE 12/28/11

SCHEDULE: VARIABLE PEAK PRICING RESIDENTIAL SERVICE TARIFF (VPPRS) RATE CODE 036

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 8 - 1A
REPLACES SHEET NO. 8 - 1
EFFECTIVE DATE ______

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY (LUGS) RATE CODE 262, 264, 265 & 267

AVAILABILITY

This rate schedule is available on an annual basis to retail customers who: 1) take service from distribution secondary lines or transformers; or 2) take service below 2.4 kV with a second transformation provided by the Company.

This schedule is not available for resale, or supplemental service. It is the customer's option whether service will be supplied under this schedule or any other schedule for which the customer is eligible. Once this schedule is selected, service will continue to be supplied under this schedule for twelve consecutive months unless a material and permanent change in the customer's load occurs or the customer is no longer eligible as described in the *Special Conditions of Service*.

A written contract may be required at the Company's option.

Service will be supplied at one delivery point and shall be at one standard voltage.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission.

SPECIAL CONDITIONS OF SERVICE

1. The Company will assist new customers in determining eligibility for this rate or any other rate schedule for which they may be eligible.

2. An existing customer is eligible for this schedule only if the customer has an average On-Peak Season monthly kilowatt-hour (kWh) usage of 8,000 kWh or less. At the end of the On-Peak Season, the average On-Peak daily kWh usage cannot exceed 266.67 kWh.

3. When a customer exceeds 40,000 kWh in total during the current On-Peak Season, the customer is billed under the applicable GS or PL rate schedule for the current month and through the next On-Peak Season before being eligible again for service under this schedule.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 8-2A
REPLACES SHEET NO. 8-2
EFFECTIVE DATE ______

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY (LUGS) RATE CODE 262, 264, 265 & 267

MONTHLY RATES

Base Service Charge	~~$35.88~~ $37.75
Base Service Charge – Unmetered Service (RATE CODE 267)	$9.59
Base Service Charge – Single-Phase 100 kWh or less usage	$21.00

Energy Charge

On-Peak Season

~~6.39~~ 2.96¢	per kWh for the first 1,500 kWh
~~6.88~~ 3.45¢	per kWh for all additional kWh

Off-Peak Season

~~5.63~~ 2.21¢	per kWh for the first 1,200 kWh
~~4.64~~ 1.23¢	per kWh for all additional kWh

Reactive Power Charges

See Reactive Power Schedule.

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is the Company's billing months of June through October, inclusive. The Off-Peak Season is the Company's billing months of November through May, inclusive.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 8-3A
REPLACES SHEET NO. 8-3
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY (LUGS) RATE CODE 262, 264, 265 & 267

OPTIONAL UNMETERED SERVICE PROVISION (267)

Under certain circumstances where a customer's load has little variation and can be reasonably estimated, a customer may, at the Company's discretion, be eligible to receive unmetered service under this provision. The monthly kWh usage for billing purposes shall be mutually agreed upon by the Company and the customer. The maximum load cannot exceed 20 kW. Service under this provision will continue for a minimum period of twelve consecutive months. The Company may, at its option, install test meters or use metered data from similar loads to verify monthly kWh usage for billing purposes. The Base Service Charge will (for customers taking service under this provision) be reduced to $9.59.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the *Base Service Charge*. The Minimum Monthly Bill shall be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 8 - 4A
REPLACES SHEET NO. 8 - 4
EFFECTIVE DATE ______

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY (LUGS) RATE CODE 262, 264, 265 & 267

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment change of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 11-1A
REPLACES SHEET NO. 11-1
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY TIME OF DAY ~~PILOT~~ (LUGSTOD) RATE CODE 269

AVAILABILITY

This tariff is limited to ~~100 TOD pilot customers plus~~ gridSMART ~~pilot~~ participants plus an additional 100 customers without an AMI meter. ~~The pilot will be available until the Final Order from the next PSO Oklahoma Corporation Commission rate review occurring after Docket No. 201000050.~~

This rate schedule is available on an annual basis to retail customers who: 1) take service from distribution secondary lines or transformers; or 2) take service below 2.4 kV with a second transformation provided by the Company.

This schedule is not available for resale, or supplemental service. It is the customer's option whether service will be supplied under this schedule or any other schedule for which the customer is eligible. Once this schedule is selected, service will continue to be supplied under this schedule for twelve consecutive months unless a material and permanent change in the customer's load occurs or the customer is no longer eligible as described in the *Special Conditions of Service*.

A written contract may be required at the Company's option.

Service will be supplied at one delivery point and shall be at one standard voltage.

The Company will furnish service in accordance with the Company's Rules, Regulations, and Conditions of Service, and the Rules and Regulations of the Oklahoma Corporation Commission.

SPECIAL CONDITIONS OF SERVICE

1. The Company will assist new customers in determining eligibility for this rate or any other rate schedule for which they may be eligible.

2. An existing customer is eligible for this schedule only if the customer has an average On-Peak Season monthly kilowatt-hour (kWh) usage of 8,000 kWh or less. At the end of the On-Peak Season, the average On-Peak daily kWh usage cannot exceed 266.67 kWh.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 11 - 2A
REPLACES SHEET NO. 11 - 2
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY TIME OF DAY ~~PILOT~~ (LUGSTOD) RATE CODE 269

3. When a customer exceeds 40,000 kWh in total during the current On-Peak Season, the customer is billed under the applicable GS or PL rate schedule for the current month and through the next On-Peak Season before being eligible again for service under this schedule.

MONTHLY RATES

Base Service Charge $37.75~~35.88~~

Energy Charge

On-Peak Season

8.150~~11.62~~¢ per kWh for all kWh in on-peak hours (hours 2:00 to 7:00, Monday-Friday)

1.230~~4.64~~¢ per kWh for all additional kWh

Off-Peak Season

2.210~~5.63~~¢ per kWh for the first 1,200 kWh

1.230~~4.64~~¢ per kWh for all additional kWh

Reactive Power Charges

See Reactive Power Schedule.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 11-3A
REPLACES SHEET NO. 11-3
EFFECTIVE DATE

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY TIME OF DAY ~~PILOT~~ (LUGSTOD) RATE CODE 269

DETERMINATION OF ON-PEAK AND OFF-PEAK SEASONS

The On-Peak Season is the Company's billing months of June through October, inclusive. The On-Peak Hours are 2:00 pm to 7:00 pm, Monday through Friday during the On-Peak Season. The Off-Peak Season is the Company's billing months of November through May, inclusive.

DETERMINATION OF MINIMUM MONTHLY BILL

The Minimum Monthly Bill is the *Base Service Charge*. The Minimum Monthly Bill shall be adjusted according to *Adjustments to Billing*. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the customer will be required to pay the Company's cost to install transformer capacity necessary to correct such interference.

ADJUSTMENTS TO BILLING

Fuel Cost Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Fuel Cost Adjustment Rider and Purchased Power Capacity Rider.

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment change of 1 ½ percent of the total amount due.

PUBLIC SERVICE COMPANY OF OKLAHOMA	SHEET NO. 11 - 4A
P.O. BOX 201	REPLACES SHEET NO. 11 - 4
TULSA, OKLAHOMA 74102-0201	EFFECTIVE DATE
PHONE: 1-888-216-3523	
KIND OF SERVICE: ELECTRIC	

SCHEDULE: LIMITED USAGE GENERAL SERVICE SECONDARY TIME OF DAY ~~PILOT~~ (LUGSTOD) RATE CODE 269

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

Attachment "2"

FILED

JUN 20 2014

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA)	CAUSE NO. PUD 201300217

JOINT STIPULATION AND SETTLEMENT AGREEMENT SIGNATURE PAGE OF
<u>WAL-MART STORES EAST, LP, AND SAM'S EAST, INC.</u>

A Joint Stipulation And Settlement Agreement was filed by Public Service Company of Oklahoma and various other signatories on June 17, 2014. Attached hereto is the signature page of Wal-Mart Stores East, LP, and Sam's East, Inc., joining in the previously filed Joint Stipulation And Settlement Agreement.

Respectfully submitted,

By [signature]

Rick D. Chamberlain, OBA # 11255
BEHRENS, WHEELER & CHAMBERLAIN
6 N.E. 63rd Street, Suite 400
Oklahoma City, OK 73105
Tel.: (405) 848-1014
Fax: (405) 848-3155
E-mail: rchamberlain@okenergylaw.com

ATTORNEY FOR INTERVENORS,
WAL-MART STORES EAST, LP,
AND SAM'S EAST, INC.

CERTIFICATE OF SERVICE

I hereby certify that on the 20th day of June, 2014, a true and correct copy of the foregoing instrument was served upon the following by means of the U.S. mail, postage prepaid, electronic mail and/or hand-delivery:

Jack P. Fite
White, Coffey, & Fite, P.C.
2200 NW 50th Street, Suite 210
Oklahoma City, OK 73112

Joann T. Stevenson
American Electric Power
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118

Deborah R. Thompson
OK Energy Firm, PLLC
P.O. Box 54632
Oklahoma City, OK 73154

Thomas P. Schroedter
D. Kenyon Williams
Hall, Estill, Hardwick, Gable,
Golden & Nelson, P.C.
320 S. Boston, Suite 200
Tulsa, OK 74103

Jennifer H. Castillo
Hall, Estill, Hardwick, Gable,
Golden & Nelson, P.C.
100 N. Broadway, Suite 2900
Oklahoma City, OK 73102

Lee W. Paden
907 S. Detroit, Suite 1012
P.O. Box 52072
Tulsa, OK 74152-0072

Jerry J. Sanger
313 Northeast 21st Street
Oklahoma City, OK 73105

Judith L. Johnson
Elizabeth A. P. Cates
Oklahoma Corporation Commission
P.O. P.O. Box 52000-2000
Oklahoma City, OK 73152-2000

Don M Powers
G Kay Powers
Powers at Law, LLC
1420 Bond Street
Edmond, OK 73034

Rhonda C. Ryan
Gerardo N. Huerta
American Electric Power Company
400 W. 15th Street, Suite 1520
Austin, TX 78701

SCOTT PRUITT
ATTORNEY GENERAL OF THE
STATE OF OKLAHOMA

By: ______________________________

Jerry J. Sanger
Assistant Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: ______________________________
Thomas P. Schroedter
Hall, Estill, Hardwick, Gable, Golden & Nelson

QUALITY OF SERVICE COALITION

By: ______________________________
Lee W. Paden

WAL-MART STORES EAST, LP

By: ______________________________
Rick D. Chamberlain

SAM'S EAST, INC.

By: ______________________________
Rick D. Chamberlain

AARP

By: ______________________________
Deborah Thompson

Attachment "3"

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	CAUSE NO. PUD 201300217

SECOND JOINT STIPULATION AND SETTLEMENT AGREEMENT

COME NOW the undersigned parties to the above entitled cause and present the following Second Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the Commission's review and approval as their compromise and settlement of the issues contained in this document between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

TERMS OF THE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Effective with the final order of the Oklahoma Corporation Commission ("OCC") approving all elements of this Joint Stipulation:

1. Electric Usage Data Protection Act.

   PSO will abide by the terms of the Electric Usage Data Protection Act, 17 O.S. 710.1 *et seq*., for the protection of customer information and usage data.

2. Advanced Metering Infrastructure (AMI).

   In addition to Section 4 of the Joint Stipulation and Settlement Agreement filed in this Cause on June 17, 2014, PSO agrees to provide the following information to the Attorney General and the Public Utility Division at the time of the annual AMI Factor redetermination, and continuing on an annual basis until cessation of the AMI Tariff:

a. Number of meters installed
b. Summary of communication plans executed
    i. Number and description of direct customer contact efforts
    ii. Number and description of mass media communication efforts
    iii. Number and description of outreach events
c. Participation rates of new tariffs
d. Number of automated connects and disconnects
    i. Automated reconnects following non-payment
    ii. Automated connects for new service or other reasons
    iii. Disconnects for non-payment
    iv. Disconnects for discontinued service or other reasons
e. Cost information
    i. Investment
    ii. Operation and Maintenance
    iii. Guaranteed savings associated with labor, vehicles, and overheads
    iv. Depreciation
    v. Property taxes
    vi. Income taxes
    vii. Return
f. AMI-related customer complaints
g. Percentage of AMI meters read
h. Demand reduction and energy savings by program

3. General Reservations.

The Stipulating Parties represent and agree that, except as specifically otherwise provided herein:

(a) This Joint Stipulation represents a negotiated settlement for the purpose of compromising and settling issues which were raised relating to this proceeding.

(b) Each of the undersigned counsel of record affirmatively represents that he or she has full authority to execute this Joint Stipulation on behalf of his or her client(s).

(c) None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation nor shall any of the Stipulating Parties be prejudiced or bound by the terms of this Joint Stipulation should any appeal of a Commission order adopting this Joint Stipulation be filed with the Oklahoma Supreme Court.

(d) Nothing contained herein shall constitute an admission by any party that any allegation or contention in these proceedings as to any of the foregoing matters is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this rate proceeding.

(e) The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, they have entered into this Joint Stipulation to settle among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as a precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its position or testimony in other causes. To the extent there is a difference, the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement, the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

4. <u>Non Severability</u>.

The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore, in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (provided, however, that the affected party or parties may consent to such modification or condition), this Joint Stipulation shall be void and of no force and effect, and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an Order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation and such Order becomes final and non-appealable.

WHEREFORE, the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement in this proceeding with respect to the issues contained within this document, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement.

PUBLIC UTILITY DIVISION
OKLAHOMA CORPORATION COMMISSION

By: ______________________________
Fairo Mitchell, Energy and Water Policy Director

PUBLIC SERVICE COMPANY OF OKLAHOMA

By: Jack P. Fite
Jack P. Fite
Joann T. Stevenson
Attorneys for Public Service Company of Oklahoma

SCOTT PRUITT
ATTORNEY GENERAL OF THE
STATE OF OKLAHOMA

By: Jerry Sanger
Jerry J. Sanger
Assistant Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: ______________________________
Thomas P. Schroedter
Hall, Estill, Hardwick, Gable, Golden & Nelson

QUALITY OF SERVICE COALITION

By: ______________________________
Lee W. Paden

WAL-MART STORES EAST, LP

By: ______________________________
Rick D. Chamberlain

SAM'S EAST, INC.

By: ______________________________
Rick D. Chamberlain

AARP

By: ______________________________
Deborah Thompson

JOE ESPOSITO

By: ______________________________
Don Powers

Attachment "4"

FILED
JUL 09 2014
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, TO BE IN COMPLIANCE WITH ORDER NO. 591185, ISSUED IN CAUSE NO. PUD 201100106, WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA.	)	Cause No. PUD 201300217

JOINT STIPULATION AND SETTLEMENT AGREEMENT SIGNATURE PAGE OF THE OKLAHOMA ATTORNEY GENERAL, E. SCOTT PRUITT

A Joint Stipulation and Settlement Agreement was filed by Public Service Company of Oklahoma (PSO) and various other signatories on June17, 2014. Attached hereto is the signature page of the Oklahoma Attorney General, E. Scott Pruitt, joining in the previously filed Joint Stipulation and Settlement Agreement, as supplemented by the SECOND JOINT STIPULATION AND SETTLEMENT AGREEMENT, filed on July 9, 2014.

Respectfully submitted,

E. SCOTT PRUITT, Oklahoma Attorney General

JERRY J. SANGER, OBA# 17131
TESSA L. HAGER, OBA# 30575
Assistant Attorney General
OKLAHOMA ATTORNEY GENERAL
313 Northeast 21st Street
Oklahoma City, Oklahoma 73105
Telephone: (405) 521-3921
Facsimile: (405) 521-6246
Jerry.Sanger@oag.ok.gov
Tessa.Hager@oag.ok.gov

CERTIFICATE OF MAILING

This is to certify that on the 9th day of July, 2014, a true and correct copy of the above and foregoing *Joint Stipulation and Settlement Agreement Signature Page of the Oklahoma Attorney General, E. Scott Pruitt*, was sent via electronic mail and/or United States Postal Service, postage fully pre-paid thereon to the following parties of interest:

Mr. Brandy Wreath, Director
OKLAHOMA CORPORATION COMMISSION
P.O. Box 52000
Oklahoma City, Oklahoma 73105
b.wreath@occemail.com

Ms. Elizabeth Cates, Deputy General Counsel
OKLAHOMA CORPORATION COMMISSION
P.O. Box 52000
Oklahoma City, Oklahoma 73105
e.cates@occemail.com

Ms. Judith Johnson, Senior Attorney
OKLAHOMA CORPORATION COMMISSION
P.O. Box 52000
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j.johnson2@occemail.com

Mr. Fairo Mitchell
Mr. Robert Thompson
Mr. David Garrett
OKLAHOMA CORPORATION COMMISSION
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Oklahoma City, Oklahoma 73105
f.mitchell@occemail.com
b.thompson@occemail.com
d.garrett@occemail.com

Mr. Jack P. Fite, Esquire
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Ms. Joann T. Stevenson, Esquire
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jtstevenson@aep.com
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jetoungate@aep.com
rcyan@aep.com
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Mr. Hank C. Steele, Case Manager
Regulatory Affairs and Case Management
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Ms. Deborah R. Thompson, Esquire
OKLAHOMA ENERGY FIRM, P.L.L.C.
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Oklahoma City, Oklahoma 73154
dthompson@okenergyfirm.com

Mr. Lee W. Paden, Esquire
907 South Detroit, Suite 1012
P.O. Box 52072
Tulsa, Oklahoma 74152-0072
lpaden@ionet.net

Mr. Don M. Powers, Esquire
Ms. G. Kay Powers, Esquire
POWERS AT LAW, L.L.C.
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Edmond, Oklahoma 73034
attorneys@powersatlaw.com

Mr. Thomas P. Schroedter, Esquire
Mr. D. Kenyon Williams, Esquire
Ms. Pat Nixon, Paralegal
HALL, ESTILL, HARDWICK, GABLE, GOLDEN & NIXON, P.C.
320 South Boston, Suite 200
Tulsa, Oklahoma 74103
tschroedter@hallestill.com
kwilliams@hallestill.com
pnixon@hallestill.com

Ms. Jennifer H. Castillo, Esquire
HALL, ESTILL, HARDWICK, GABLE, GOLDEN & NIXON, P.C.
100 North Broadway Avenue, Suite 2900
Oklahoma City, Oklahoma 73102
jcastillo@hallestill.com

Mr. Rick D. Chamberlain, Esquire
BEHRENS, WHEELER & CHAMBERLAIN
6 Northeast 63rd Street, Suite 400
Oklahoma City, Oklahoma 73105
rchamberlain@okenergylaw.com

Holly Lyn Hampton

HOLLY LYN HAMPTON
Legal Assistant to the Public Utility Unit
Oklahoma Attorney General's Office

Attachment "5"

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. PUD 201300217

OKLAHOMA INDUSTRIAL ENERGY CONSUMER

SIGNATURE PAGE TO SECOND JOINT

STIPULATION AND SETTLEMENT AGREEMENT

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO. 591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	CAUSE NO. PUD 201300217

SECOND JOINT STIPULATION AND SETTLEMENT AGREEMENT

COME NOW the undersigned parties to the above entitled cause and present the following Second Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the Commission's review and approval as their compromise and settlement of the issues contained in this document between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

TERMS OF THE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Effective with the final order of the Oklahoma Corporation Commission ("OCC") approving all elements of this Joint Stipulation:

1. Electric Usage Data Protection Act.

   PSO will abide by the terms of the Electric Usage Data Protection Act, 17 O.S. 710.1 *et seq.*, for the protection of customer information and usage data.

2. Advanced Metering Infrastructure (AMI).

   In addition to Section 4 of the Joint Stipulation and Settlement Agreement filed in this Cause on June 17, 2014, PSO agrees to provide the following information to the Attorney General and the Public Utility Division at the time of the annual AMI Factor redetermination, and continuing on an annual basis until cessation of the AMI Tariff:

PUBLIC UTILITY DIVISION
OKLAHOMA CORPORATION COMMISSION

By: ______________________________
Fairo Mitchell, Energy and Water Policy Director

PUBLIC SERVICE COMPANY OF OKLAHOMA

By: Jack P. Fite
Jack P. Fite
Joann T. Stevenson
Attorneys for Public Service Company of Oklahoma

SCOTT PRUITT
ATTORNEY GENERAL OF THE
STATE OF OKLAHOMA

By: Jerry Sanger
Jerry J. Sanger
Assistant Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: ______________________________
Thomas P. Schroedter
Hall, Estill, Hardwick, Gable, Golden & Nelson

QUALITY OF SERVICE COALITION

By: ______________________________
Lee W. Paden

Attachment "6"

sd-1

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA TO BE IN COMPLIANCE WITH ORDER NO.591185 ISSUED IN CAUSE NO. PUD 201100106 WHICH REQUIRES A BASE RATE CASE TO BE FILED BY PSO AND THE RESULTING ADJUSTMENT IN ITS RATES AND CHARGES AND TERMS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	CAUSE NO. PUD 201300217 ORDER NO. 627830

PARTIAL TRANSCRIPT OF PROCEEDINGS

JUNE 25, 2014

FILED
JUL 30 2014
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

OFFICIAL REPORTER:

CAROL S. DENNIS, RPR, CSR

APPEARANCES

JACK FITE, Attorney At Law, and JOANN STEVENSON, Attorney At Law, appeared on behalf of Public Service Company of Oklahoma.

JUDITH L. JOHNSON, Attorney At Law, appeared on behalf of the Public Utility Division, Oklahoma Corporation Commission.

JERRY J. SANGER, Attorney At Law, and TESSA L. HAGER, Attorney At Law, appeared on behalf of the Office of the Attorney General.

THOMAS P. SCHROEDTER, Attorney At Law, and JENNIFER CASTILLO, Attorney At Law, appeared on behalf of Oklahoma Industrial Energy Consumers.

LEE W. PADEN, Attorney At Law, appeared on behalf of Quality of Service Coalition.

RICK D. CHAMBERLAIN, Attorney At Law, appeared on behalf of Wal-Mart Stores East, LP and Sam's East, Inc.

A P P E A R A N C E S (Continued)

DEBORAH R. THOMPSON, Attorney At Law, appeared on behalf of AARP.

DON POWERS, Attorney At Law, appered on behalf of Joe Esposito.

sd-4

P R O C E E D I N G S

* * * * *

THE COURT: We have opened the merits of the proceeding here today in accordance with notice and in accordance with the Commission's order, and at this time I would request the Public Comment list to address those who have joined us here today. Thank you for being here for Public Comment.

(Ms. Ludwick handed document to the Court.)

THE COURT: At this time the first name is Joe Esposito.

MR. ESPOSITO: Your Honor, can I confer with my lawyer for a second?

THE COURT: Yes.

(Pause.)

MR. ESPOSITO: Good morning, Your Honor.

THE COURT: Good morning, Mr. Esposito.

MR. ESPOSITO: Everybody else. I live in Owasso. I'm a little bit challenged with my throat right now because of the WiFi in the corner up there, and so that causes me some difficulty talking. I was -- there's two things probably at this time. I have a series of some documents here.

Can I have these filed under Public Comment?

THE COURT: Submit those to the staff counsel.

MR. ESPOSITO: Okay. Thank you.

THE COURT: Thank you.

MR. ESPOSITO: And the other thing is, Your Honor, you know, we talk about the wireless technology, but I don't know that -- I bring a perspective here I believe in this case, since I've been affected more than most and I have been studying this for the last two years, I can show you what it looks like in this courtroom. Would you be willing to look at it?

THE COURT: Yes.

MR. ESPOSITO: This meter reads microwave radiation. It reads that WiFi. It reads this baby monitor. It reads smart meters or AMI meters. And so, I know we all participate in the verbal acknowledgement, but I don't think many people have seen this.

And the reason of my concern is at my home in Owasso the radiation is coming through the walls in my house, and the levels are so high it pegs this meter. So, I had to nail aluminum screen wire on the whole south side of my home and my roof to block the radiation.

So, I just -- for your -- I'm kind of a teacher, and if you would like to see it, I'd be happy to demonstrate it, just to show you in the court what we're talking about.

THE COURT: Would you, Mr. Esposito, describe what you are about -- what you are proposing to demonstrate?

MR. ESPOSITO: Would I describe?

THE COURT: Yes, describe it. Describe what happens, the steps you are going to take.

MR. ESPOSITO: Okay. Thank you. What's happening right now is we're all being affected by WiFi in this room, and you cannot see it. You can't hear it. You can't touch it. You can't feel it, unless you have a device that reads it. And in today's society we're being inundated with that kind of radiation.

And I also have a document from Olle Johansson, neuroscientist in Sweden, addressed to the Corporation Commission about that exact issue. And this issue has been probably going on for almost the last nineteen months with the Oklahoma Corporation Commission in other cases. But nobody ever really gets to see it. And so, I would like to show it to you.

THE COURT: And what would happen if you showed it?

MR. ESPOSITO: It's just a noise. You're just going to hear a noise, is all you are going to hear.

THE COURT: Other counsel -- is there -- are there any objections from anyone in the courtroom regarding this? Mr. Esposito?

MR. ESPOSITO: Thank you, Your Honor. I came in early because I like to see what environment I'm in because

I'm affected by this environment. This is a thousand dollar HFE 35C meter, and it measures this radiation that we're particularly talking about.

So, I am going to turn it on, and it is going to have to stabilize for a second. It reads at 200 microwatts per meter squared and two thousand microwatts per meter squared. Right now it's dropping down to, say -- it varies -- five point one, which is very safe. If I take this meter to the country, it reads zero zero zero and maybe point one or point two.

But when you come into this environment in the city -- we just drove down here with this meter on, and every time you pass like cell towers or whatever, it usually just pegs the meter because of the extremely high radiation levels. And so, depending on the science you listen to or you read, there's a difference of opinion. And there's the FCC's guideline, and then there is science that has been coming out like the Bioinitiative Report, which is a thousand four hundred and seventy-nine pages of documented science.

(Interruption.)

A. Okay. Somebody's cell phone just went off just now. You know, there's a sign right here that says please turn off all cell phones and cell devices off. They interfere with the microphone system. And that's interesting because we tell people to do that, but we don't protect the people

We are protecting the microphones, not the people.

So, let me just show you. I can go into a place and show you -- the -- everything has a signature. WiFi has a signature. So, where I go, I go into people's homes or anywhere, and I can read this stuff. So, let me just show you (demonstrating).

If you were in here earlier, that was -- it's a very, clear distinct WiFi. It goes tick, tick, tick, tick, tick. But there's so many cell phones I'm getting a lot of interference right now. So, it's very hard like -- you know, so I'm reading all this interference. And everything has interference.

And let me -- let me show you this. I've been doing this for almost two years, and I've been quite a bit over the state. This -- this is a baby monitor. They put this on the mom's hip, and then there's a camera that goes where the baby is. So, when I turn it on, this goes a thousand feet (demonstrating.) I turned it off, and I will turn that off.

And so, the thing is people do not feel feel, see or touch this unless you are hypersensitive. And I am. And how you get there, I'm not sure sometimes. But the public doesn't know this is happening to them.

I've been researching this for almost two years. They knew this back in 1932. I've got a 1972 military document, two thousand three hundred studies, this Navy, a hundred and six pages, five pages of health symptoms. And so, people don't understand. They will have an ailment and not know what their problem is. Most of -- like Derek Lewellen -- I think he has a business degree -- but most people in this room are not science-based people. Maybe there are, and forgive me. But that's where all this is coming from. And so, in this --

MS. JOHNSON: Your Honor, objection. PUD would like to object on the grounds that we thought that Mr. Esposito was going to give Public Comment, but this is borderlining on giving testimony. He is represented by an attorney, Mr. Powers, who has had the opportunity to provide evidence, to obtain expert witnesses, and I believe that this is going beyond the scope of giving Public Comment.

THE COURT: Mr. Powers? This is your client.

MR. POWERS: Well, I think what Mr. Esposito is doing I believe it's -- it can be considered Public Comment. It is not anything that anybody else couldn't produce and bring forward. It is not anything that anybody else couldn't find out by doing some research on their own.

I don't know that it needed to be handled as a formal matter within -- within the -- within the rate case, but it certainly is, I think, ancillary information that the

Court, the Corporation Commission and maybe the other parties ought to know if they are certainly not aware of it, because I don't think they are.

THE COURT: Other counsel wish to be heard? Ms. Johnson, I understand your objection, and I'm going to note it for the record. Mr. Esposito, I'm going to ask you to continue with your comments. Make sure that they are Public Comment.

MR. ESPOSITO: Right. Thank you very much, Your Honor.

THE COURT: Thank you.

MR. ESPOSITO: In this group of documents -- I think there's nineteen -- I learned of these things that the most -- the public are not familiar with. And on January the 8th -- well, November the 8th -- 7th, 2012, I learned of it.

I came to the Oklahoma Corporation Commission January the 8th, 2013, with information about all this. And I also have here my personal three-page testimony of what happened to me physically and physiologically. And so, I'd just like to let the Judge know and the other participants that I think I bring a perspective that nobody else really has, and I would like to offer my services, whatever would be helpful, to explain those things.

THE COURT: Please proceed, Mr. Esposito.

MR. ESPOSITO: If I can just kind of summarize my physical condition, we were -- my wife and I -- I was having -- I have a degree in physiology, and I'm a little more sensitive to physical issues than most people. I was having two major health symptoms at the time back then. And my front teeth on bottom and the roof of my mouth felt like somebody poured Alka-Seltzer in my mouth at night. I had a pain in my left groin, started out as a pinpoint and inflamed my whole leg.

And when I learned about what was happening with smart meters, I followed some instructions from a You-tube doctor where we put lead around the outside of the box where the meter is at about three o'clock on a Friday afternoon, and by 1:00 o'clock Saturday morning this symptom and this symptom -- my teeth and leg stopped immediately. I did not need a pharmaceutical. I didn't need a doctor to diagnose me.

And I brought that notarized copy to the Corporation Commission and the entire State legislature, trying to help people understand that this radiation is like somebody putting their thumb on you and pressing down, and as soon as you let go then things would clear up, at which time after I learned that, I built a Faraday cage, which is just aluminum screen wire.

And if you are in the military these people know about

Faraday cages because they build whole buildings and rooms out of Faraday cages because that blocks the radiation. That's why I had to put aluminum screen wire on my house, was to block the radiation. And the radiation with this meter inside that Faraday cage is point one, which means it is very safe.

And so, I just wanted to bring to the attention of the Court that there's information to avail and that I'd like to have these filed.

THE COURT: You have counsel. I would ask you to present a copy to the staff, a copy, and seek counsel regarding your filing.

MR. ESPOSITO: Okay. Thank you very much.

THE COURT: Now, Mr. Esposito, I must ask is there anything further that you wish to present here today?

MR. ESPOSITO: No, ma'am.

THE COURT: You've had an opportunity --

MR. ESPOSITO: Yes.

THE COURT: We appreciate your being present.

MR. ESPOSITO: Thank you.

THE COURT: Thank you very much.

* * * * *

(This concludes the requested portion of the transcript proceedings.)

sd-13

STATE OF OKLAHOMA)
) ss:
COUNTY OF OKLAHOMA COUNTY)

C E R T I F I C A T E

I, Carol S. Dennis, Registered Professional Reporter, Certified Shorthand Reporter, Official Court Reporter for the Corporation Commission of the State of Oklahoma, do hereby certify that on June 25, 2014, the preceding testimony was taken by me in machine shorthand and was thereafter reduced to typewritten form by me. The foregoing transcript is a true and accurate record of the testimony given to the best of my understanding and ability.

Whereupon, I have set my hand and seal on this the 20th day of July, 2014.

Carol S. Dennis
CAROL S. DENNIS, RPR, CSR
OFFICIAL COURT REPORTER
OKLAHOMA CORPORATION COMMISSION

12-31-14