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BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF THE EMPIRE DISTRICT ELECTRIC COMPANY, A KANSAS CORPORATION, FOR ANADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. PUD 201600468

REPORT OF THE ADMINISTRATIVE LAW JUDGE ON THE FULL EVIDENTIARY HEARING

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I. HEARING DATES, LOCATIONS AND APPEARANCES OF LEGAL COUNSEL

On May 10-12, 2017, Administrative Law Judge ("ALJ") Ben Jackson conducted a full evidentiary hearing on the application of Empire District Electric Company for a general rate order. The hearing occurred in Courtroom B and Courtroom 301, Jim Thorpe Building, 2101 North Lincoln Boulevard, Oklahoma City Oklahoma. At the hearing, the following attorneys entered appearances: Jack P. Fite for Empire District Electric Company ("EDE"); Deputy Attorney General Dara M. Derryberry and Assistant Attorney General Jared B. Haines for Oklahoma Attorney General Mike Hunter ("AG"); Thomas P. Schroedter for the Oklahoma Industrial Energy Consumers ("OIEC"); and Natasha M. Scott, Deputy General Counsel and Assistant General Counsels Olivia Waldkoetter and Patrick M. Ahern for the Commission's Public Utility Division ("PUD").

II. SUMMARY

The EDE application is a rate base, rate of return ratemaking for EDE, which operates an electricity transmission and distribution system serving ten towns in Ottawa, Delaware and Craig Counties, with a total of 4,689 customers. Current rates and charges were set by settlement under Order No. 592623 (Exhibit No. 136) issued on January 4, 2012. EDE started the current ratemaking in 2016 with a request for a $3.8 million dollar increase, which EDE later dropped to $2.6 million dollars. The 2016 test year plus six months for known and measurable changes ended December 31, 2016, but OIEC and the AG want a one-to-two year moratorium on general rates to see if a new test year after EDE's merger with Liberty Utilities will show significant savings to EDE's customers. In the meantime, OIEC and AG propose only giving EDE an environmental compliance rider to compensate EDE for $304 million dollars in environmental compliance equipment, but the rider proposals would not address an additional $365.5 million dollars in new plant additions.

The ALJ recommends going forward with a general rate order, because the Commission needs to address EDE's revenue deficiency as well as customer rate shock concerns seen in the public comments. In addition, the ratepayers will benefit from avoiding the cost of another full rate case within twelve to twenty-four months, as well as carrying charges on that $365.5 million dollars for new plant additions, which are now used and useful to ratepayers. This ratemaking is driven mainly by $669.5 million dollars in capital expenditures, a drop in the return on equity, changes in incentive compensation and payroll, and rate design adjustments. Table 1 compares the positions of the Parties, Intervener and the ALJ.

Table 1

FINAL POSITION COMPARISON

Parties	Empire (P.10 Errata Exhibit filed on 4-20)	PUD (Ex 138)	OIEC Alternate Proposal(Ex140 Revised)	OIEC ECP Rider (see attached)	AG ECP Rider (see attached)	ALJ Recommendation
Revised Pro Forma Rate Base	$43,275,753	$43,275,753	$3,071,159** (Empire proposed Oklahoma increase)	$804,205 (1st year of rider)***	$866,968 (1st year of rider)	$43,275,753
(ROE) ROR	(9.9%) 7.59%	(9.9%) 7.59%				(9.5%) 7.39%
Required Operating Revenue	$3,284,629*	$3,284,630	$2,494,458 (OIEC Adjustments)**			$3,198,078
Revised Pro Forma Operating Income	$1,429,712	$1,540,573				$1,585,774
Return (Deficiency)	($1,854,917)*	($1,744,057)				$1,612,304
Income Tax Gross Up Factor	163.077%	163.076%				163.076%
Revised Pro Forma Revenue (Deficiency)	($3,024,940)	($2,844,138)	$576,701 (Rate increase after OIEC Adjustments)**			$2,629,281

***Slight difference due to Empire rounding.**
****Difference largely due to OIEC disallowing $365,500,000 in total company rate base as plant additions not supported in company direct testimony and OIEC advocating for 9.0% ROE.**
Difference in riders largely due to OIEC using a 9.0% ROE.

The ALJ rejected OIEC's revenue requirement (Exhibit No. 140), mainly because it omitted the above-described $365.5 million dollars for plant additions. The ALJ generally adopted PUD's position but lowered the return on equity from PUD's 9.9 percent to 9.5 percent based on the AG's expert witness testimony, and also because of the AG's expert witness testimony, the ALJ denied any recovery for long-term incentive compensation, SERP and payroll adjustments. Due to concern over hardship in the Residential Class, the ALJ rejected EDE's request to increase the regular customer charge from $12.59 dollars to $20.59 and the total electric residential customer charge from $12.50 to $25.00 per month. In any event, the ALJ also amortized the $238,000 dollars rate case expense over three years without interest. As a result, the ALJ's proposed revenue requirement increase totalled $2,629,281 dollars. To allocate costs fairly, the ALJ allocated costs equally to all customer classes, and the ALJ recommends a mitigation plan. PUD sponsored their mitigation plan, and EDE asked for two changes to it, namely a three year step, with year one at fifty percent of the revenue requirement and EDE also asked for carrying charges presented in testimony. The ALJ adopted EDE's two suggestions. The result for the first year is recovery of $1,314,641 dollars plus carrying charges. Additionally, the ALJ accepted EDE's proposal to re-base the Southwest Power Pool Transmision Tariff Schedule by shifting $377,214 dollars to base rates.

III. JURISDICTION AND NOTICE

The Applicant is EDE, an integrated electric utility and a wholly owned subsidiary of Liberty Utilities, Inc. ("LU Central"). EDE, a Kansas corporation, is authorized to do business in Oklahoma and provides transmission and distribution services in northeastern Oklahoma. EDE seeks increases in rates and charges because of an alleged revenue deficiency since issuance of Order No. 592623, the current general rate order issued on January 4, 2012. EDE's current application seeks rate relief under Okla. Const. art. IX, §§ 18 & 19 and 17 O.S. 2011 §152. In that regard, the Commission has jurisdiction of the subject matter and persons. Notice was given as required by law and Commission rules. After a full evidentiary hearing and based on the evidence discussed below, the Commission has jurisdiction to issue a final order in this cause.

IV. SERVICE TERRITORY AND CUSTOMER BASE

EDE is an investor-owned utility providing electric, natural gas (through its wholly owned subsidiary Empire District Gas Company), and water service, with approximately 218,000 customers located in Missouri, Kansas, Oklahoma and Arkansas. EDE also has a subsidiary which provides fiber optic service. Organized in Topeka, Kansas on October 16, 1909, EDE is a Kansas corporation currently headquartered in Joplin, Missouri. Although established in 1909, EDE traces its history to the late nineteenth century as the mining industry grew in what is today EDE's service area. As mining companies were created, electric motors began to replace mules and steam powered engines in several of the mines. EDE was established to address the needs of those mines. Today, EDE has 1,200 miles of transmission and 1,300 megawatts of owned capacity to serve approximately 165,000 electricity customers. The current application concerns only electric transmission and distribution in Oklahoma, because EDE has no generation in Oklahoma. At the hearing on the merits, no one had a map of the EDE system.

As a result, the ALJ asked for maps to be submitted as late filed exhibits, which are shown below as Figure 1 and Figure 2 in Appendix B. Figure 1 is an EDE website map depicting EDE's four State service area. As seen on Figure 1, approximately eighty-five percent of the EDE system lies in Missouri, with the rest located in the abutting corners of Kansas, Oklahoma, and Arkansas. Oklahoma has around three percent of the total customer base. Based on cost of service studies, the Oklahoma jurisdiction allocation factors vary between 2.7349 percent and 3.1268 percent. Figure 2 is an EDE map of the Oklahoma portion of the EDE system. EDE only operates in Ottawa, Delaware and Craig Counties, and Figure 2 shows the ten towns served, namely, Cardin, Picher, Commerce, North Miami, Welch, Blue Jacket, Quapaw, Narcissa, Fairland and Wyandotte. Picher no longer has permanent residents because of the EPA buyout of local homes during EPA's Tar Creek Superfund cleanup.

EDE's customer base consists of 4,689 customers. Table 2[1] compares consumption by customer class between 2010 and 2016 test years.

Table 2
Comparison of 2010 and 2016 Test Years

Test Year	2010*	2016**
Total Oklahoma Customers	4,741	4,685
Oklahoma Jurisdiction	2.848%	2.767%
Residential Customers	3,816	3,780
Actual Residential Sales	55,611,117 kWh	47,279,918 kWh
Commercial Customers	825	802
Actual Annual Commercial Sales	11,999,058 kWh	12,284,848 kWh
Industrial Customers	13	12
Actual Annual Industrial Sales	38,066,216 kWh	27,584,081 kWh
Number of Public Authority Customers (Street and Highway Lighting)	87	91

*PUD 201100082 Kelly S. Walters Direct Testimony Page 3, Lines 16-18.
**PUD 201600468 Brad P. Beecher Direct Testimony Page 4, Lines 1-3.

V. EDE's RATE INCREASE REQUEST

EDE's last general rate case occurred in 2011 in Cause No. PUD 201100082, which used calendar year 2010 for the test year and resulted in a settlement finalized by Order No.592623, issued on January 4, 2012. That order granted a general rate increase of $633,436 or 4.1 percent, with a return on equity of 10.19 percent and overall rate of return of 8.27 percent. The current

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[1] The 2016 data in Table 2 comes from the corporate overview in Cause No. PUD 201100082, Direct Testimony of Kelley S. Walters p. 3, lines 16-18, and the corporate overview in Cause No. PUD 201600468, Direct Testimony of Brad P. Beecher, p.4, lines 1-3.

application initially asked for $3.8 million dollars per year but now seeks a $2.6 million dollars per year with an overall rate of return of 7.59 percent and a return on equity of 9.9 percent.

VI. PROCEDURAL HISTORY

In the 2012 rate order, the Commission approved the Southwest Power Pool Transmission Tariff schedule rider ("SPPTC"). As outlined in that order, "the SPPTC will be reviewed for the purposes of extension, modification or termination during the next EDE base rate case, which will be filed no later than 42 months following the implementation of the SPPTC." As such, EDE was required to file a base rate case on or before July 5, 2015. In order to comply, EDE filed an application on January 12, 2015, requesting to amend the provision of the SPPTC order by removing the requirement to file a base rate case within 42 months. (*See* Cause No. PUD 201500012, Order No. 639419). In Cause No. PUD 201500012 EDE stated that it was making significant investments in its generation fleet, and due to the timing of the investments associated with the various projects, it would likely require the filing of two base rate cases, one in 2015 and another base rate case to be filed in the third quarter of 2016. In an effort to avoid the significant costs associated with litigating two rate cases within a short period, EDE requested the amendment to the SPPTC tariff. In Cause No. PUD 201500012, PUD witness Mr. Geoffrey M. Rush testified that EDE had completed improvements in its Asbury Plant and was in the process of converting the Riverton 12 Plant into a combined cycle unit by mid-2016. Mr. Rush further stated that it was PUD's opinion that back-to-back rate cases would not only be burdensome to EDE and its customers, but would not serve the public interest. (*See* Order No. 639419, pages 2 and 3 for testimony summary).

As outlined in the Commission's Findings of Fact and Conclusions of Law in Cause No. PUD 201500012, Order No 639419:

> "THE COMMISSION FURTHER FINDS that it would not be in the public interest to have multiple rate cases and therefore the requested amendment to the Southwest Power Pool Transmission Tariff set forth in the testimony of Mr. Owens, and attached hereto as Attachment "A," is granted."

After receiving the Commission's approval to delay a base rate case, EDE filed an application on October 21, 2015, seeking a change in its rates and charges pursuant to the Commission's reciprocity rules, as defined in OAC 165:5-70-60. (Cause No. PUD 201500379). However, once the proposed rates were approved in Missouri and submitted to the Commission, both the AG and the OIEC objected to the increase in base rates under the reciprocity rule. The AG and

OIEC stated that if EDE wants an increase in its Oklahoma base rates, another rate case should be filed with Oklahoma specific information. EDE agreed to work with the parties and on November 2, 2016, EDE filed a Motion to Dismiss Cause No. PUD 201500379, so that a case could be filed using the Commission's Minimum Filing Requirements containing Oklahoma specific information. The Commission issued an Order granting the motion to dismiss (Order No. 659346). The dismissal was granted without prejudice to refilling another base rate case.

With respect to the current application, EDE filed its Notice of Intent on November 2, 2016. The Notice of Intent signified EDE's intention to file a general rate case to review the rates and charges for electricity service to its customers in Oklahoma.

On November 8, 2016, Deputy Attorney General Dara M. Derryberry and Assistant Attorney General Jared B. Haines filed an Entry of Appearance on behalf of the Attorney General of Oklahoma Mike Hunter.

On December 21, 2016, EDE filed its Application and basic filing package, which included accounting schedules and the direct testimony of witnesses Brad P. Beecher, Bryan S. Owens, Blake A. Martens, Aaron J. Doll, Bethany Q. King, Jeffery P. Lee, Thomas J. Sullivan, Dr. James H. Vander Weide, Mark Quan, and Dr. H. Edwin Overcast.

On December 22, 2016, Thomas P. Schroedter filed an Entry of Appearance on behalf of OIEC. On the same day, Assistant Attorney General Vilard Mullaliu filed his Entry of Appearance on behalf of the AG.

On December 29, 2016, EDE filed a Motion to Establish Procedural Schedule and a Motion for Protective Order. The Commission issued a Notice of Hearing for each motion to be heard before the ALJ on January 5, 2017. At that hearing, the Motion to Establish Procedural Schedule was continued until January 19, 2017, while the Motion for Protective Order was accepted by the ALJ with an amendment supported by the parties.

PUD of the Commission filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements on January 12, 2017.

The Motion for Protective Order came before the Commission on its signing agenda on January 18, 2017. The Commission entered its Order Granting Motion for Protective Order, Order No. 659,980, on that date. On January 19, 2017, the Motion for Procedural Schedule was continued for a week until January 26, 2017. On January 26, 2017, the motion was continued for another week until February 2, 2017. Before the hearing on February 2, 2017, the parties and

ALJ agreed to continue the hearing on the Motion for Procedural Schedule to February 16, 2017. The Motion for Procedural Schedule was then continued until February 23, 2017.

On February 16, 2017, EDE filed a Motion to Determine Notice. The Commission executed a Notice of Hearing for the motion to be heard before the ALJ on February 23, 2017.

At the hearing before the ALJ on February 23, 2017, the parties submitted an agreed procedural schedule and customer notice.

The Motion to Determine Notice and Motion to Establish Procedural Schedule came before the Commission on its signing agenda on March 2, 2017. At the signing agenda, the Commission approved an Order Granting Motion to Determine Notice, Order No. 661,607, and its Order Granting Motion to Establish Procedural Schedule, Order No. 661,610.

On March 13, 2017, several witnesses filed responsive testimony. David J. Garrett and Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. Elbert D. Thomas, Geoffrey M. Rush, Kathy Champion, Kiran Patel, McKlein Aguirre, Robert C. Thompson, and Tonya Hinex-Ford filed testimony on behalf of PUD. PUD also filed its Accounting Exhibit on the same day.

On March 20, 2017, the AG filed the Notice of Withdrawal as Counsel of Vilard Mullaliu.

Several witnesses filed rate design testimony on March 22, 2017. Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. Kathy Champion and Jeremy K. Schwartz filed testimony on behalf of PUD.

Public comments were filed on March 31, 2017.

On April 3, 2017, several witnesses filed rebuttal testimony. Christopher D. Krygier, Timothy S. Lyons, Blake A. Mertens, H. Edwin Overcast, Robert W. Sager, Thomas J. Sullivan, and Dr. James H. Vander Weide filed testimony on behalf of EDE. David J. Garrett and Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. David Melvin and Jeremy K. Schwartz filed testimony on behalf of PUD.

Two of EDE's witnesses also filed testimony adopting the testimony of prior witnesses on April 3, 2017. Timothy S. Lyons adopted the direct testimony of Bryan S. Owens, and David Swain adopted the direct testimony of Brad P. Beecher.

Public comments were filed on April 3, 2017, and on April 7, 2017.

OIEC filed its Motion to Dismiss or, in the Alternative, Motion to Strike on April 10, 2017. On the same day, the Commission executed a Notice of Hearing for the motion to be heard before the ALJ on April 21, 2017.

On April 17, 2017, Geoffrey M. Rush filed surrebuttal testimony on behalf of PUD. OIEC, PUD, and the AG each filed a surrebuttal issues list on the same day.

Public comments were filed on April 19, 2017.

On April 20, 2017, the parties filed summaries of testimony. EDE filed the Summary of the Direct Testimony of Aaron J. Doll, the Summary of the Direct Testimony of Bethany Q. King, the Summary of the Rebuttal Testimony of Christopher D. Krygier, the Summary of the Direct Testimony of Jeffery P. Lee, the Summary of the Direct Testimony of Bryan S. Owens Adopted by Mr. Timothy Lyons and Rebuttal Testimony, the Summary of Direct and Rebuttal Testimonies of Blake A. Mertens, the Summary of the Direct and Rebuttal Testimonies of Dr. H. Edwin Overcast, the Summary of the Direct Testimony of Mark Quan, the Summary of the Rebuttal Testimony of Robert W. Sager, the Summary of the Direct Testimony of David Swain, and the Summary of the Direct and Rebuttal Testimonies of Dr. James H. Vander Weide.

PUD filed the Summary Testimony of McKlein Aguirre, the Rate Design Summary Testimony of Kathy Champion, the Summary Testimony of Tonya Hinex-Ford, the Summary Testimony of David Melvin, the Summary Testimony of Kiran Patel, the Testimony Summary of Geoffrey M. Rush, the Cost of Service Summary Testimony of Jeremy K. Schwartz, the Summary Testimony of Elbert Thomas, and the Summary Testimony of Robert C. Thompson. The AG filed Summary of Responsive Testimony of Edwin C. Farrar, the Summary of Rate Design Testimony of Edwin C. Farrar, and the Summary of Rebuttal Testimony of Edwin C. Farrar. OIEC filed the Testimony Summary of David J. Garrett and the Testimony Summary of Mark E. Garrett.

EDE also filed *errata* accounting schedules and a Response to OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike on April 20, 2017.

The parties appeared at pretrial conference on April 21, 2017. At the pretrial conference, PUD, the AG, and OIEC jointly moved that the hearing on the merits be continued from April 24, 2017, to May 10, 2017, in light of EDE's errata filings the previous day. EDE did not oppose the motion. The ALJ agreed. The ALJ also announced that OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike could be advanced to a hearing *en banc* before the Commission rather than being heard by the ALJ.

Public comments were filed on April 21, 24, 25, 27, and 28, 2017. Public comments were also filed on May 1, 2017.

Both the continuance of the hearing on the merits and the advance of OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike came before the Commission at its signing agenda on May 2, 2017. The Commission entered its Order Advancing to Commission *en banc* Oklahoma Industrial Energy Consumers' Motion to Dismiss or, in the Alternative, Motion to Strike and Setting Hearing Date, Order No. 663,323, on that date. The hearing on the motion was set for May 4, 2017, and the hearing on the merits was set to begin on May 10, 2017.

Public comments were filed on May 2 and 3, 2017.

The hearing on OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike was heard before the Commission *en banc* on May 4, 2017. The Commission took the matter under advisement.

Public comments were filed on May 5 and 8, 2017.

On May 9, 2017, the Commission considered OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike at its signing agenda. On that day, the Commission entered its Order Denying Motion to Dismiss, Or in the Alternative, Motion to Strike, Order No. 663,516.

The hearing on the merits began on May 10, 2017, and concluded on May 12, 2017. At the close of the evidentiary hearing, the ALJ closed the record and took the matter under advisement.

Public comments were also filed on May 10, 11, 12, 16, 17, 18, and 22, 2017.

VII. RATEMAKING METHOD

The ratemaking method used in this report is the rate base- rate-of-return method, which is the only method that the Commission has ever used for EDE.

VIII. TEST YEAR

EDE selected the test year, which consists of twelve consecutive months ending on June 30, 2016. Under 17 O.S. 2011 §284, the Commission adds six months to the test year for known and measurable changes. Consequently, balances on June 30, 2016, were adjusted for known and measurable changes through December 31, 2016.

IX. LEGAL STANDARDS

EDE's application seeks a general rate order under 17 O.S. 2011 §152, which amended the Oklahoma Constitution's ratemaking scheme starting in 1913. 1913 Ok. Sess. Laws Ch. 93, p. 150 §2, (emerg. eff. March 25, 1913). In that regard, Ok. Const. Art. IX §18 requires rates and charges that are reasonable and just, but the Commission's authority is limited to setting rates, charges, and terms and conditions of service, because Ok. Const. Art. IX, §18 failed to grant the Commission either the power of internal management or control incident to ownership. *Public Service Co. of Ok v. Ok. Corp. Comm.*, 1996 OK 43, 918 P.,2d 733, 739. Under the legislative scheme, the Commission's power is limited to determining whether or not an act by a utility affects public rights and what steps are needed to avoid an effect that is unreasonable, unfair or prejudicial to public rights. *Lone Star Gas Co. v. Ok. Corp. Comm.*, 1934 OK 396, 39 P.2d 547, 553. However, the Commission lacks the power to demand prior approval of construction plans for a new plant, but once the plant is built, the Commission is empowered to ascertain the plant's effect on rates. *Public Service of Okla. v. Ok. Corp. Comm.*, 1983 OK 124, 688 P.2d 1274, 1277. In that regard, the Commission may disallow any improvident cost or unnecessary item, if not used and useful to public service or if a cost is excessive, unwarranted, unreasonable or incurred in bad faith. *PSO*, pp. 1277-1281. To that end, the Commission has a duty to ensure that the utility charges are the lowest reasonable rates. *State v. OG&E*, 1975 OK 40 ¶20, 536 P.2d 887, 891. And the Commission has the power to prevent a utility from passing on to ratepayers unreasonable costs. *Valiant Tel. Co. v. Ok. Corp. Comm.*, 1982 OK 159, 656 P.2d 273, 275.

Avoiding rate shock is a primary ratemaking goal especially for the residential customers since increases in basic needs can cause hardship for customers on low or fixed income. The term "rate shock" sometimes known as "bill shock" refers to a customer's awareness of a large rate increase. *See* Goodman, *The Process of Ratemaking*, vol. II pg. 899 (Public Utilities Reports, Inc. 1998). In public comments in this cause, EDE customers on low and fixed incomes explained hardship from EDE's high proposed rate increases. Along that line, the courts have long recognized that, while an agency may consider value of service, there is a limit to what the traffic will bear and it is necessary to avoid unduly burdensome rate increases. *New England Divisions Case*, 261 U.S. 184, 191 (1923). Historically, the Commission sets rates and charges using the *End Result Doctrine* arising from *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), where the Court reasoned:

> It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. (*Hope* at 602).

The Court further stated that the ratemaking process involves a balancing of the investor and consumer interests. (*Hope* at 603). Reasonable balancing requires factual findings establishing a balance between the investor's interest in maintaining financial integrity and access to capital markets versus the consumer's interest in being charged non-exploitative rates. *Jersey Central Power & Light v. F.E.R.C* , 810 F.2d 1168, 1172 (D.C., Cir. 1987); *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). In establishing the prudent total cost of service for a utility, the *Hope Case* shifts the focus of debate from a valuation of the capital component of service to a balancing of interests test.

X. MAJOR ISSUES

The outcome of this cause depends on the answers to several issues. The first issue is whether to delay general ratemaking to see if the 2017 merger of EDE and LU Central will generate significant savings, which will lower rates. The next issue, which is the central issue in this cause, is what to do about the size of EDE's requested rate increase. Initially, EDE sought a $3.8 million dollar increase in its revenue requirement, but dropped that number to $3.02 million dollars at the evidentiary hearing. In its proposed findings, EDE further reduced rate increase request to $2.6 million dollars, which would still generate a 22.39 percent total rate increase to all customer classes. The ALJ proposes additional adjustments to the revenue requirement lowering the increase to approximately $2.3 million dollars, translating into a 20.33 percent total rate increase to all customer class. Nevertheless, OIEC in its Exhibit 140 proposes $576,701 for the increase in the revenue requirement, translating into a six percent total rate increase for all customer classes. Regardless of which increase in revenue requirement is selected, OIEC wants to shift much of the rate increase to the residential customers, based on OIEC's argument about unfair cross-subsidies from disparities in relative rates of return among the customer classes. Consequently, the next three questions are: what should be the increase in the revenue requirement, what is a fair allocation of those costs to the customers classes, and should the Commission phase in rate increases over several years?

XI. SUMMARY OF THE TESTMONY

Appendix A contains the summaries of the witness testimony, all under oath.

XII. PUBLIC COMMENT

During the prehearing conference, the ALJ received comments from Quapaw Nation citizens, who expressed concern about economic hardship to low income and retired persons. During the full evidentiary hearing, no one gave public comment, but the ALJ did receive written comments from civic leaders, small business owners and residential customers.

XIII. PROGRAM FOR LOW INCOME AND FIXED INCOME CUSTOMERS

The Public Comment File in this cause contains written comments from low and fixed income customers who are concerned about whether they can pay their electric bills under EDE's proposed rate increase. The ALJ's report addresses those concerns in several ways. To begin with, the Commission has a constitutional and statutory duty to set the lowest reasonable rates on a non-discriminatory basis. EDE's proposed residential tariff appears in Schedule N of EDE's Basic Filing and provides a discount for the first six-hundred kilowatt hours consumed each month. The ALJ finds that proposal to be reasonable and just. The ALJ further finds that the ALJ's recommendations for changes in the EDE's revenue requirement and rate design also benefit all residential customers. However, the ALJ also notes that public utility services for low income customers are "affordable" only if the sum of all services does not exceed six percent of income. If a low income customer is having trouble paying a bill, the customer should contact PUD's Consumer Service Department, which can mediate a bill dispute as well as advise the customer about federal and state programs for low income customers, e.g., the Oklahoma Low Income Home Energy Assistance Program (LIHEAP) and the Commission's Lifeline Service Program for telephone service.

XIV. ALGONQUIN MERGER AND THE ENVIRONMENTAL COMPLIANCE RIDER PROPOSAL

A threshold question in this ratemaking is whether the Commission should issue a general rate order in view of a change in conditions or knowledge of conditions occurring after the test-year plus six-months, which ended December 31, 2016. On February 9, 2016, EDE announced its merger with Algonquin Power and Utilities Corp. ("APUC") of Oakville, Ontario, Canada. APUC, a North American diversified utility holding company, bought the capital stock of EDE for US$2.4 billion dollars. APUC operates utilities through Algonquin Power Co. and Liberty Utilities Co. ("LU Canada"), which is the holding company for LU Central, which is now the holding company for EDE. In a triangular merger between EDE, Liberty Subsidiary Corp. (Merger Subsidiary), and LU Central, EDE became a wholly-owned subsidiary of LU Central in January, 2017, which is after the ratemaking test period ended.[2] Since completion of the merger in January, 2017, EDE and LU Central have not entered into any affiliate transactions to share personnel or equipment. Also, EDE has not had access to LU Central's bulk purchasing power to buy equipment, materials or supplies. Consequently, it is not known what specific benefits to ratepayers will be generated by the merger. Nevertheless, AG witness Ed Farrar and OIEC witness Mark Garrett both recommended that the Commission should not entertain a full base rate case until a full and complete test year following EDE's acquisition by LU Central could be provided. According to Mr. Farrar, his suggested approach would allow time for any economic efficiency from the LU Central acquisition of EDE to be incorporated in rates. (Farrar Rate Design, p. 3, ll. 13-20); (Garrett Reb., p. 8, ll. 4-6).

Both AG witness Mr. Farrar and OIEC witness Mr. Garrett recommend versions of a compliance rider referred to as the Environmental Compliance Plan Rider ("ECP") or "The Kansas Plan." The two rider proposals come from a 2016 settlement in Kansas (Exhibit No. 132). According to Mr. Farrar, the Commission should limit the new cost born by EDE's customers to the costs incurred for environmental compliance upgrades, similar to what has been approved by the Kansas Corporation Commission ("KCC"). In Kansas, the Commission allowed environmental costs to be passed through a rider. The Commission provided for a future rate case filing, after a specified period of time, following the acquisition of EDE by LU Central. According to Mr. Farrar, this approach had merit because it allowed time for any efficiencies from the acquisition to be included in EDE's permanent rates, and it allowed customers to more gradually adjust to an increase in their rates. (Farrar Resp., p. 6, ll. 4-11). Mr. Garrett provided similar testimony when he stated that the Commission could authorize a rider for EDE's collection of the capital cost of the Asbury and Riverton 12 projects, subject to refund and

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[2] The Commission was the last State utility agency to approve the merger, and the Commission approved the merger by Order No. 652551, effective May 12, 2016.

subject to a Commission review for prudence of these investments in EDE's next Oklahoma rate case. At this time, all other cost increases would be rejected under Mr. Garrett's recommendation but could be considered in EDE's next Oklahoma rate filing, which, according to Mr. Garrett, was consistent with the actions of the KCC. (Garrett Resp., p. 11, ll. 4-9).

Table 4 compares the AG and OIEC calculations for first year of an environmental compliance rider.

Table 3

Oklahoma Environmental Compliance Rider Calculation Comparison
Rider to be subject to refund and annual true-up

Party	Total Company*	OIEC (2.75% Oklahoma allocation)	AG (2.7677% Oklahoma allocation)
Plant in Service	$303,933,214	$8,364,242	$8,411,960
Accumulated Depreciation	($13,820,981)	($380,353)	($382,523)
Accumulated Deferred Income Tax	($56,786,408)	($1,562,762)	($1,571,677)
Total	$233,325,825	$6,421,127	$6,457,759
ROR		9.79%	10.6874%
Return		$628,406	$690,167
Depreciation	$6,388,032	$175,799	$176,802
First Year Rider Revenue		$804,205**	$866,968***

*Total Company reflects costs of environmental upgrades to Riverton 12 and Asbury.
**Mark Garrett Responsive Testimony Page 10.
***Ed Farrar Responsive Testimony Page 8.

Basically, the rider proposals continue with current rates, postpone general ratemaking for one-to-two years, use an environmental compliance rider to compensate EDE only for environmental compliance equipments, and fail to consider $365.5 million dollars for new equipment now in service.

The ALJ recommends that the Commission reject both rider proposals. Through its filing and notice, EDE has invoked the Commission's power to review rates, and EDE's current rates do not provide an adequate return. As reflected in Section B, Schedule 1 of EDE's Minimum Filing Requirements, the return on rate base during the test year, under existing rates, was 2.28%. (Section B., Schedule 1, l.9). The return on equity during the test year under existing rates is a negative 0.71%. (Section B., Schedule 1, l. 11). Therefore, adoption of the "Kansas plan" will not produce a reasonable result. Next, OIEC and the AG ask the Commission to ignore EDE and PUD's testimony about $365.5 million dollars in capital investment that EDE has presented for inclusion in rate base. OIEC and AG contend that EDE failed to prove that the investments were prudent. That contention is contrary to fact as will be shown later in this report under the heading Plant in Service. Be that as it may, OIEC and AG speculate that the potential post-merger savings make delay reasonable, but OIEC and AG did not present any evidence showing that their imagined savings will even offset the carrying charges on the $365.5 million dollars. The ALJ submits that if the Commission does not put the new plant additions in rate base at this time, then the customers will owe finance charges accruing on the investment until the Commission adjusts rate base in the next general rate case.

XV. TRADITIONAL BASE RATE CASE ITEMS

A. Rate Base

1. Plant in Service

In its initial filing in this cause, the Company proposed to include in rate base $73,910,187 of gross Utility Plant in Service as of June 30, 2016. (Section B, Schedule 1, l. 7). The Company's Utility Plant in Service included in rate base was updated to $74,841,078 to reflect Plant in Service recorded to FERC Account 101 and Completed Construction Not Classified recorded to FERC Account 106 as of December 31, 2016. (Errata Schedule TSL-2.01).

OIEC witness, Mark Garrett, recommended a reduction to the proposed total Company rate base of $365.5 million, or an approximately $10,124,350 reduction to the Oklahoma jurisdictional rate base. (Resp. test., p.37, ll. 17-38, as updated by OIEC Hearing Exhibit 140, l. 21). The basis for Mr. Garrett's proposed adjustment was that the Commission had not been provided with sufficient evidence to determine whether the plant additions were prudent and whether the costs associated with the plant additions were just and reasonable. (*Ibid*).

Both EDE witness Mr. Mertens and PUD witness Mr. Melvin, provided testimony regarding plant investments made by the Company since the last base rate case. Mr. Mertens described various investments made by EDE in an effort to improve system reliability. He also provided information regarding each electric plant project since the last rate case, and continuing through six-months after the end of the test year, costing more than $1 million. (Mertens Reb., BAM Attachment 1). PUD witness Mr. Melvin provided testimony regarding PUD's onsite audit, which included discussion with the Directors of Engineering, Substation Engineering and Distribution Engineering who explained the reasons for and benefits of various projects. (Melvin

Reb., p. 7, ll. 11-19, p. 8, ll. 1-2). As outlined by EDE personnel, several projects were the direct result of mandated requirements by the North American Electric Group Reliability Corporation ("NERC"), as well as upgrades to transmission lines required by the Southwest Power Pool. (Melvin Reb., p. 8, ll. 12-19). Mr. Melvin testified that the competitive bid process was used in most situations and a fixed price contract was EDE's preferred method of contracting (Melvin Reb, p. 10, ll. 11-21). Mr. Melvin testified that after PUD's review of the Application, associated testimonies, schedules, data requests and responses, statues and rules, and onsite audits, PUD recommends the Commission accept the adjustments to plant in service requested in the Application, including the six-month post-test year adjustment of $930,891 made by PUD witness Robert C. Thompson, which results in PUD revised pro forma plant in service of $74,841,078. PUD believes the adjustments for "plant additions are prudent and the associated costs are reasonable." (Melvin Reb., rebuttal at pg. 6, ll. 4lines 8-9 and PUD Revised Accounting Exhibit filed May 15, 2017, Section B, Schedule 1, Line 1). Neither Mr. Mertens nor Mr. Melvin was cross-examined regarding the plant additions they supported in testimony.

The ALJ agrees with the standard of review set forth in EDE's response to OIEC's Motion to Dismiss or, In the Alternative Motion to Strike filed April 20, 2017. EDE met the requirements found at OAC 165:70-1-1 *et seq.*, (MFRs) as was acknowledged in a response dated January 12, 2017, by PUD that stated, "Empire's Application Package in this cause is in substantial compliance with the minimum filing requirements..." With respect to the minimum filing requirement, this Commission has stated that "it is intended to define the information required to be filed and made available in connection with a proposed general rate change in order to facilitate an investigation of and hearing on such rates."

While the Company incurred significant capital expenditures to improve the reliability of the system as described in the testimony of EDE witness Mertens, there were also many other plant investments made by EDE as part of ordinary, day-to-day capital expenditures, generally made by an electric utility to keep the system operational. Schedule BAM-1, attached to the Rebuttal testimony of Mr. Mertens, explains the other capital outlays, which were for ordinary maintenance or upgrades.

The Oklahoma Supreme Court has stated that good faith is presumed on the part of public utility managers regarding their judgment about prudent outlays, including outlays for capital. (Emphasis supplied). *Turpen v. Oklahoma Corp. Com'n*, 1988 OK 126, 769 P.2d 1309, 1330.

The Oklahoma Supreme Court has further stated, "that the regulatory agency bears the burden of proving the payments to non-affiliates is unreasonable." (Turpen, *supra* at 1323). As there are no allegations that any of the payments in the $365,500,000 ($10,124,350 Oklahoma jurisdiction) rate base adjustment proposed by OIEC are made to affiliates or are imprudent, the ALJ finds that there is substantial evidence found in Mr. Mertens and Mr. Melvin's testimonies to include the amounts in rate base.

2. <u>Accumulated Depreciation</u>

EDE requested to include, as a reduction to rate base, the June 30, 2016 balances of the Accumulated Depreciation recorded in FERC Account 108 and the Accumulated Amortization of intangible plant recorded in FERC Account 111.

The PUD, AG, and OIEC all recommended an increase of $1,255,668 to accumulated depreciation, resulting in an accumulated depreciation balance of $23,395,442, to reflect the balance as of December 31, 2016. (Section B, Schedule 1, PUD Revised Accounting Exhibit filed May 15, 2017.) EDE agreed with the adjustment. (Lyons, Reb. p. 7, lines 5, 10 and 11).

3. <u>Other Prepayments</u>

EDE calculated a thirteen-month test year average for the prepayment balance. PUD agreed with the Company's use of a thirteen-month average; however, PUD's thirteen-month average was based on thirteen months ending December 31, 2016, versus the Company's period ending June 30, 2016. PUD's thirteen-month post-test year average for the total Company is $9,071,872. Oklahoma's allocation factor is 2.7526% resulting in an Oklahoma jurisdiction prepayment adjustment of $249,709. Therefore, PUD recommends a $22,003 increase to the requested level of prepayments. (Patel Resp., p. 13, ll. 7-14, p. 14, ll. 1-9). No parties contested this adjustment.

4. <u>Materials and Supplies and Fuel Inventories</u>

Materials and supplies have three components, which are 1) materials, 2) transmission and distribution, and 3) clearing accounts. EDE's Oklahoma jurisdictional thirteen-month average materials and supplies balance ending June 30, 2016, was $719,238. PUD used a thirteen-month post-test year average ending December 31, 2016, resulting in a $21,269 increase in materials and supplies. PUD's thirteen-month post-test year average for the total Company is $27,076,201. Based on the Oklahoma allocation factor of 2.7349%, the resulting Oklahoma jurisdictional balance is $740,507. (Patel Resp., p. 11, ll. 17-19, p. 12, ll. 1-10). No party contested this adjustment.

Additionally, EDE used the thirteen-month average test year balance as of June 30, 2016, for the Fuel Inventory balance. As shown in Section B-2, EDE's thirteen-month average balance as of June 30, 2016, was $28,177,344. Based on the Company's Oklahoma jurisdiction allocation factor of 3.1268%, the Oklahoma jurisdictional Fuel Inventory balance was $881,049. PUD used a thirteen-month post-test year average balance ending December 31, 2016, resulting in an Oklahoma jurisdictional Fuel Inventory balance of $815,281, which is a decrease of $65,768 from the Company's proposed balance. (Patel Resp., p. 12, ll. 11-16, p. 13, ll. 1-7). No party contested this adjustment.

5. <u>Customer Deposits and Customer Advances and Contributions in aid of Construction</u>

EDE's filing calculated a thirteen-month Oklahoma jurisdictional average balance of $405,888 for Customer Deposits as of June 30, 2016. PUD proposed a thirteen-month average balance of $418,779 as of December 31, 2016. Because rate base is reduced by the amount of customer deposits, which are considered customer supplied capital, this adjustment results in a $12,893 reduction to rate base. (Thomas Resp., p. 10, ll. 1-6). No party contested this adjustment.

The Company's filing included a thirteen-month average balance of $4,531 for Contributions in Aid of Construction as of June 30, 2016. Because the six-month post-test year balance at December 31, 2016, was not materially different, there were no proposed adjustments to the balance of Contributions in Aid of Construction.(Thomas Dir. P.8 ll 2-9).

6. <u>Cash Working Capital</u>

No party proposed an adjustment to EDE's proposed cash working capital of $130,864.

7. <u>Accumulated Deferred Income Taxes (ADIT)</u>

On April 20, 2017, EDE filed an *Errata*, reflecting a six-month post-test year net ADIT balance of $10,407,245 for the Oklahoma jurisdiction as of December 31, 2016. As set forth in the OCC Minimum Filing Requirements, OAC 165:70-5-4 (3) (B) (iii), ADIT is a reduction to rate base. (Errata J-3). No party contested the ADIT adjustment proposed by EDE.

B. Rate of Return

1. <u>Capital Structure</u>

All parties agreed that a capital structure containing a debt ratio of 50.32% and a 49.68% common equity ratio was reasonable to use in this proceeding.

2. <u>Cost of Capital</u>

(a) Cost of Debt

The ALJ recommends that EDE's imbedded cost of long-term debt is 5.30% (See EDE's Minimum Filing Requirements Section F. Schedule 4). No party filed testimony or exhibits opposing the use of EDE's proposed cost of long-term debt.

(b) Return on Equity (ROE)

Table 4 below shows the final EOE recommendations.

Table 4

Party	**Percent**
EDE	9.9
PUD	9.9
AG	9.3 or 9.5
OIEC	9.0
ALJ	9.5

Mr. Geoffrey M. Rush testified on behalf of PUD concerning the cost of capital. Mr. Rush used a Quarterly Approximation DCF model. As in prior rate cases, the three primary inputs in the DCF model *i.e.* stock price, current dividend, and the growth rate, resulted in disagreement regarding the growth rate among the three witnesses that used the DCF model since the stock price and dividends are known inputs based upon recorded data. Mr. Rush's average DCF result of the proxy companies using the Quarterly Approximation DCF model was 7.12%. (Rush Resp., p. 25, ll. 10-12). Mr. Rush also used a Capital Asset Pricing model ("CAPM"). The CAPM model has primarily three terms required to calculate the required return. The three primary terms of the CAPM model are (1) the risk free rate (2) the Beta co-efficient, and (3) market risk premium, which is the required return on the overall market less the risk-free rate. The average CAPM cost of equity for each proxy company in Mr. Rush's analysis was 6.79%. (Rush Resp., p. 34, ll. 7-9). Mr. Rush also performed a comparable earnings analysis, which is an accounting based model that relies on available accounting data, particularly the return earned on book equity. The comparable earnings model involves averaging the earned returns on equity of other utility companies. For the comparable average Mr. Rush used the annual earned return on equity for each of the proxy companies from 2007-2016 which he averaged resulting in a composite average of 9.82%. (Rush Resp., p. 35, ll. 20-21) The average cost of equity resulting from each of the three models used by Mr. Rush was 7.91%. (Rush Resp., p. 36, ll. 2-3). Mr. Rush accepted the Company's proposed cost of debt of 5.30% and the Company's existing capital structure. Mr. Rush's recommended cost of equity was 9.90%, which was the mid-point in what he considered to be a range of reasonableness of 9.65% – 10.15%. (Rush Resp., p. 46, ll. 8-9).

OIEC witness, Mr. David Garrett did not object to EDE's proposed debt ratio of 50.32% or the cost of debt of 5.30%. However, Mr. Garrett did disagree with EDE's cost of equity capital. The result of Mr. Garrett's DCF model was 7.6%. His CAPM model resulted in a cost of equity of 7.4%, with an average of 7.5%. (Garrett Resp., p. 75, l. 9) Mr. Garrett's average market cost of equity was 8.1% (Garrett Resp., p. 77, l. 4). Although not contained in either Mr. Garrett's DCF or CAPM model, he recommended a 9.0% ROE. (Garrett Resp. test., p. 78).

EDE Witness Dr. Vander Weide performed five different equity models, which were the discounted cash flow (9.3%); Ex ante risk premium (10.5%); Ex post risk premium (10.0%); CAPM-historical (9.7%); and the CAPM-DCF based (10.2%) which resulted in an average of 9.9%. Dr. Vander Weide's proxy companies' cost of equity was in the range of 9.3%-10.5% with an average result equaling 9.9% ROE which was his recommendation. (Vander Weide Dir., p. 48, l. 12).

The ALJ recommends 9.5 percent for ROE and adopts the AG's Mr. Farrar's opinion that the Commission should consider reducing the ROE relative to that granted in PSO and OG&E's last rate cases to encourage better reliability with the implication that its ROE would be set at a "normal level" in a future proceeding "once the company had sufficiently improved reliability". (Reb. test., p. 8, ll. 17-20). The ALJ rejects Mr. Farrar's alternative value of 9.3 percent derived from the Kansas settlement. The ALJ cannot determine if that percentage is reasonable without seeing all riders if there are other riders. With respect to OIEC's position, 9.0 percent is unreasonably low. David Garrett contends that most public utility commissions set ROE too high. However, the ALJ finds that Mr. Garrett understates risk especially in his analysis of EDE. The basic problem here is that EDE is a small utility with large capital costs for new equipment but insufficient load growth to pay for it.

C. Operating Income/Expenses

1. EDE Operating Income

In EDE's Basic Filing (Exhibit No. 4), Section H, Schedule 1 provides test year utility operating income and adjustments. Section H, Schedule 2 sets forth adjustments to operating income and Section H, Schedule 3, contains the explanation of adjustments to operating income. (Owens/Lyons, Dir. test., p. 12, ll. 9-11). Section H, Schedule 2 also sets forth the Oklahoma allocator for the various adjustments. EDE made fifty-two adjustments which were mostly uncontested by the other parties in the proceeding.

2. EDE Payroll and Payroll Related Taxes

PUD, AG and OIEC all recommended that EDE's payroll and payroll related taxes be reduced. AG and OIEC propose adjustments to disallow unfilled positions and future pay raises resulting in a proposed Oklahoma jurisdictional reduction of $63,037. (Hearing Exhibit 140, MG 2.5) EDE did not agree with this adjustment, specifically stating that seventeen of the twenty-seven positions had been filled and that the remaining positions provided important support for the Company's operations. (Lyons, Reb., p. 4, ll. 11-14). Mr. Lyons testified during the preceding that at the time the Company made its filing, which was based upon the test year ending June 30, 2016, there were twenty-seven vacant positions. (Tr. May 10, p.m., p. 89, ll. 23-25). Mr. Lyons further testified that since that time, seventeen of those positions have subsequently been filled. Additional clarification was provided regarding the components of the vacant positions and Mr. Lyons indicated there are other positions where people have left, either to other positions within the Company or they have left the Company completely, and those have created vacant positions and do have an impact on the vacant position numbers. (Tr. May 10, p.m., p. 90, ll. 3-9). The ALJ finds that the Commission has discretion about whether to allow recovery for vacant positions even though a vacancy is not a cost incurred during the test year plus six-months, but EDE did not show a compelling reason for recovery for those vacancies. Therefore, the ALJ recommends that the Commission denies recovery for vacancies and future pay raises.

3. Depreciation

Only EDE and OIEC produced depreciation studies in this cause. EDE's current Oklahoma depreciation rates are based on Order 592623 in PUD Cause No 201100082. The depreciation report prepared for EDE for this Cause was based on an analysis of plant activity through December 31, 2014, with recognition given to known and measurable changes since that date. The summary tables in EDE's report are presented using plant-in-service and accumulated reserve balances as of June 30, 2015. (Sullivan Dir., TJS-2, p. 3). For unit property, specifically production plant, EDE witness Mr. Sullivan developed remaining life depreciation expense rates based on the prospective life span (retirement date) of each generating unit. Included was an allowance for interim additions and retirements of individual pieces of property, as well as an adjustment for net salvage (gross salvage less cost of removal). (Sullivan Dir.,TJS-2, p. 3).

For mass property, specifically transmission, distribution, and general plant, the basis for the recommended accrual rates began with the development of appropriate average service lives ("ASL") and Iowa curves for each plant account using the actuarial analysis method. After developing the recommended ASL and Iowa curves, Mr. Sullivan adjusted for net salvage to develop a whole life depreciation rate.

Mr. Sullivan further recommended establishing depreciation reserve amortization for the negative reserve balance and the cost of decommissioning of the Riverton Steam Plants (Units 7 and 8) and Riverton Unit 9, which were retired in June 2015 but have not been fully depreciated. This amortization, totaling $2.3 million annually, should recover the balance of EDE's investment in Riverton Units 7, 8, and 9 over the next five years. (Sullivan Dir., Schedule TJS-2, p. 4). The Oklahoma jurisdictional portion of the amortization of Riverton Units 7, 8 & 9 would be $63,273 annually. (Section H, Schedule 2, Adj. 17.)

As stated previously, OIEC was the only other party to propose specific depreciation rates. PUD used the existing rates in their accounting schedule (Exhibit No. 138), and AG used EDE's existing depreciation rates in their proposed environmental rider found on page 8 of Mr. Farrar's Responsive testimony. During cross examination, Mr. Farrar stated his recommendation for depreciation rates by answering the following question "Is your recommendation for the Commission to stretch out the depreciation rates as long as possible?" "Yes". (Tr. May 11, p. 113, ll. 13-16). Although as stated earlier, Mr. Farrar produced no study to support his recommendation for the Commission to stretch out the depreciation rates as long as possible.

OIEC witness Mr. David Garrett recommended total adjustments to EDE's Oklahoma jurisdictional proposed depreciation rates amounting to a negative $439,856. According to Mr. Garrett, there were several primary factors driving OIEC's depreciation adjustments which include (1) removing proposed terminal net salvage on production plants, removing future, unapproved plant additions from the Company's calculated depreciation rates on the production accounts, and leaving the current life span estimates for the productions units unchanged for a reduction of $229,806; (2) proposing different Iowa curve shapes average lives for various transmission, distribution, and general accounts for a reduction of $154,303; and (3) amortizing the unrecovered costs of Riverton Units 7, 8, and 9 over the estimated remaining life of Riverton 12 for an additional reduction of $55,748. (Garrett Resp., p. 6, ll. 6-12, p. 7, ll. 1-2).

The ALJ will address the amortization period of Riverton Units 7, 8 and 9; EDE's production facilities and EDE's mass property accounts.

4. Riverton Units

Mr. Garrett proposed amortization of the un-depreciated portion of the retired Riverton Units 7, 8 and 9 over forty-two years. According to Mr. Garrett, closing of the units was part of EDE's environmental compliance plan and therefore the remaining life of Riverton Unit 12, which was installed in 2007 converting the unit to combined cycle natural gas, should be the rational for using the 42 year time period. (Garrett Resp., p. 33, ll. 9-17).

Mr. Garrett's recommendation would result in a depreciation and amortization period of 109 years for Riverton Unit 7 (placed in service in 1950); 105 years for Riverton Unit 8 (placed in service in 1954); and 95 years for Riverton Unit 9 (placed in service in 1964). (Sullivan Reb., p. 5, ll. 14-19). Mr. Sullivan further stated in his rebuttal testimony that Mr. Garrett inaccurately implied that the environmental compliance plan was the only driver for the retirement of the old units. (Sullivan Reb., p. 5, ll. 19-20).

The ALJ recommends using EDE's proposed amortization period for the three Riverton Units. It is unreasonable to use depreciation and amortization periods over a century long, as proposed by OIEC witness Garrett, since amortization should correspond to the un-depreciated lives of these assets.

5. Production Units

Mr. Garrett made three adjustments to EDE's proposed depreciation rates for production units which he described on page 19 of his Responsive testimony beginning at line 2 where he stated: "(1) I removed terminal net salvage due to lack of support through the site-specific decommissioning studies; (2) I recalculated the company's proposed production rates without including future unapproved plant additions; and (3) I allocated the depreciable costs over the currently-approved life spans of the company's production units."

The ALJ agrees with EDE not to include any terminal net salvage in the determination of the depreciation rates for the Company's production units as is indicated by their response to OIEC data request 4.2 attached to the Rebuttal Testimony of Mr. Sullivan. As stated in the answer to the data request, all net salvage rates for production accounts are for interim retirements.

The ALJ also recommends rejecting Mr. Garrett's recalculation of asset lives without including future plant additions. Mr. Garrett's adjustment is an example of single-issue accounting because he rejects the capital expenditures made to accomplish the life extension, but he accepts the extra life that is the result of those expenditures. If the capital expenditures made to accomplish the life extension are not included then the extra life should also not be included. The quotation found in Mr. Sullivan's Rebuttal Testimony on page 20 of pages 6-38 through 6-39 of the publication *Accounting for Public Utilities* is instructive on this matter.

Mr. Farrar also rejected the use of future plant additions (Reb. test., p. 12, ll. 1-12) and incorrectly states this Commission has never accepted future plant additions in a depreciation study. Mr. Garrett does acknowledge that this Commission has accepted interim additions in the past (Tr. May 11, p.m., p. 118, ll. 16-17) but states in his opinion the Company had not met its burden of proof. The ALJ recommends that the Commission accept the extra life as the result of the expenditures, as well as the capital expenditures themselves, as proposed by EDE. However, if the capital expenditures are disallowed, the ALJ recommends that the Commission also make a determination that the extra life added by additions should be disallowed.

It can be further determined from the record that Mr. Garrett did not allocate the depreciable costs over the currently approved life spans of the Company's production units as stated in his testimony. It is also clear that he adopted several of Mr. Sullivan's recommendations to change to the currently used life spans. For example, Mr. Garrett used the same retirement date for Iatan 2 that Mr. Sullivan used which was an increase in the retirement date from 2060 to 2070. (Sullivan Reb., p. 7, ll. 15-18). The ALJ recommends rejecting the adjustment to production plant, due to the inconsistencies in Mr. Garrett's testimony.

6. Mass Property Accounts

The ALJ also recommends rejection of Mr. Garrett's adjustment to mass property accounts. Mr. Garrett stated that he obtained the Company's historical plant data to develop the observed life tables for each account. (Garrett Resp., p. 20, ll. 3-5). That was not the case. As clearly set forth in Mr. Sullivan's Rebuttal Testimony, Mr. Garrett only went back to 1960, wherein the entire data set for many of the accounts went as far back as 1900. (Sullivan Reb., p. 22, ll. 12-18).

Mr. Garrett's use of Iowa curves were a comparison of his Iowa curves, based upon the 1960 database and Mr. Sullivan's which included all of the database back to 1900. Further, Mr. Garrett's graphs are further truncated at 50% surviving. In essence, Mr. Garrett made an inaccurate comparison to Mr. Sullivan's proposed Iowa curves. (Sullivan Reb., p. 23, ll. 4-12). Nowhere in Mr. Garrett's testimony did he indicate these differences between his work and that of Mr. Sullivan's.

The ALJ finds that although Mr. Sullivan's depreciation study will further the goal of setting the best long run rates, the ALJ adopts PUD's position and uses the existing depreciation rates, because of the rate shock problem. Consequently, the ALJ finds that depreciation and amortization expenses as of 12/31/16 should be $2,220,738.

7. <u>Annual and Long-term Incentive Compensation</u>

EDE requested 100% recovery of both the short-term incentive compensation and long-term incentive compensation. (Lyons Reb., p. 4, ll. 6-8). During the hearing, Mr. Lyons testified that there were different levels of employee incentive compensation plans. There was an executive officer level, a department head level, and a salary employee level. (Tr. May 10, p.m., p. 33, ll. 2-7). The incentive plan metrics included, but were not limited to, expense control, regulatory performance, completion of projects, financial performance and customer service. (Tr. May 11, p.m., p. 33, ll. 11-13). EDE considered the amount of dollars associated with each of the metrics, including earnings per share, as highly confidential and the information was provided in camera. (Tr. May 10, p.m., ll. 5-15).

PUD witness Mr. Geoffrey Rush recommended that the Commission disallow 50% of short-term compensation and 75% of the long-term compensation. (Resp. test., p. 43, ll.18-20). According to Mr. Rush, the Commission has consistently disallowed 50% of short-term incentive compensation and 75% of long-term incentive compensation. (Resp. test., p. 43, ll. 4-6). Mr. Rush testified that the rationale behind the Commission's decision was that performance measures that result in the payment of long-term incentive compensation were financial goals that benefit shareholders rather than customers and that the same rationale applied to disallowance of 50% of short-term incentive compensation. In this case, 25% of long-term incentive compensation is based on financial performance and 50% of short-term incentive compensation is based on financial performance. (Rush Resp. test., p. 43, ll. 9-13). Mr. Rush's recommendations result in a reduction of $50,778 on the revenue requirement (Sec. H, Sch. 3, PUD revised accounting exhibit filed May 15, 2017).

OIEC witness, Mr. Mark Garrett proposed excluding 100% of the annual incentive compensation plan expense (Garrett Resp. test., p. 17, l. 11). And AG witness Farrar recommended the disallowance of half of short-term incentive compensation expenses (Farrar Reb. test., p. 14, l.12) and 100% of long-term incentive compensation. (Farrar Reb. test., p. 17, ll. 1-4).

The ALJ finds that Mr. Farrar's position correctly reflects the Commission's position in the recent PSO and OG&E general rate orders where the Commission rejected compensation survey/ fair market value arguments in favor of their view of OIEC's "value to the customer" argument. Therefore, the ALJ recommends recovery of fifty percent of short term incentive competition, and no recovery of other incentive compensation. The twenty-five percent drop from PUD's position represents an additional reduction of $8,614 dollars.

8. <u>SERP</u>

PUD, AG and OIEC opposed the recovery of SERP costs in rates. The SERP is part of the overall compensation package and therefore EDE has requested the full recovery of costs, consistent with the rational set forth for annual and incentive compensation. However, the ALJ cannot recommend SERP, because the ALJ disagrees with EDE's rationale for long-term incentive compensation. In total, the ALJ adjustments on SERP, vacancies and future raises would be a reduction of $65,098 dollars.

9. <u>Pension and OPEB Expenses</u>

EDE witness Mr. Jeff Lee testified that the Company was requesting total annual Oklahoma pension expense of $289,356, which represents an increase of $78,505 to the amounts authorized in rates pursuant to Cause No. PUD 201100082. This total includes actuarially determined expense of $240,660 and a five-year tracker amortization of $48,696 for the pension plan. According to Mr. Lee, EDE is requesting total annual Oklahoma OPEB expense of $44,451, which represents a decrease of $32,441 to the amounts currently authorized. This total includes actuarially determined expense of $50,136 and a negative five-year tracker amortization of ($5,685). (Lee Direct, p. 2, ll. 6-16). PUD witness Rush recommended the Commission adopt EDE's requested increase to pension and decrease to OPEB expenses. (Rush Resp., p. 45, ll. 3-5). Neither OIEC nor AG took issue with the recommendation of EDE and PUD. Therefore, the ALJ adopts EDE's position on pension and OPEB expenses.

XVI. REVENUE DEFICIENCY

Based upon the findings and recommendations contained herein, the ALJ recommends that the Commission find:

Empire's Revised Pro Forma Rate Base	**$43,275,753**
Rate of Return	**7.39%**
Required Operating Revenue	**$3,198,078**
Revised Pro Forma Operating Income	**$1,585,774**
Return Deficiency	**($1,612,304)**
Income Tax Gross Up Factor	**163.076%**
Revised Pro Forma Revenue Deficiency	**($2,629,281)**

XVII. COST-OF-SERVICE

EDE incurs cost to provide service to customers in four retail jurisdictions in Arkansas, Kansas, Missouri and Oklahoma, as well as being subject to the jurisdiction of the FERC. Therefore, 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 the specific jurisdiction. Once the jurisdictional costs are determined, a class (that is residential, commercial, industrial, and others) cost-of-service allocates or assigns the jurisdictional cost-of-service to the different classes based on the customers' use of EDE's electric system. The result is the 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 cost to the individual retail customer classes to evaluate the cost EDE incurs in providing electric service to each individual retail customer class. The ALJ recommends EDE's cost-of-service study be used for the jurisdictional cost separation, as it was an uncontested issue.

OIEC was the only party to make a recommendation to modify the Company's filed cost-of-service study. Mr. Mark Garrett recommended modifying EDE's cost-of-service study to use a 4 Coincident Peak ("4CP") methodology for allocation of transmission costs rather than EDE's proposed 12 Coincident Peak ("12CP") methodology. (March 22 Resp. test., p. 4, ll. 12-15).

Mr. Garrett further recommended that the class cost-of-service study be modified to use a 4 Coincident Peak average and excess ("4CP AED") methodology for allocation of production costs rather than EDE's proposed 12 Coincident Peak average and excess ("12CP AED") methodology. (March 22 Resp., p. 4, ll. 21-24).

Mr. Garrett testified that although the Commission has consistently authorized the 4CP for production costs for PSO and OG&E, he relied upon more than prior Commission orders. According to Mr. Garrett, because EDE is a dual peaking system, he looked at the peak load for each month and developed a slightly different 4CP. He used two summer months and two winter months to develop the 4CP for EDE. (Tr. May 12, p. 17, ll. 11-18). Mr. Garrett did not agree with Dr. Overcast that the production allocation factor should be developed by taking into consideration the monthly total capacity demand on the system. Mr. Garrett testified that the Commission had always relied upon peak load and did not consider other factors like forced outages and schedule maintenance. In Mr. Garrett's opinion, this approach diluted the peak loads figures. He further testified that in his opinion, FERC allocations were different than retail. (Tr. May 12, p. 73, l. 25, p. 74, ll. 1-22).

Mr. Garrett testified that the use of a 4CP allocation method for transmission is justified by the significant differences in monthly loading which makes, the 12CP methodology inapplicable to the EDE system. (Responsive testimony dated March 22, 2017, p. 9, ll. 8-16).

In response to Mr. Garrett's recommended modifications to the transmission and production allocators, Dr. Overcast testified that since no two utilities are alike, it was necessary to understand the factors causing costs for each individual utility. (Overcast Reb., p. 3, ll. 14-16). Dr. Overcast testified that Mr. Garrett's approach was inconsistent with FERC standards for determining the appropriate peak allocation factor. FERC standards require that the utility consider "the full range of a company's operating realities including, an addition to the system demand, schedule maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments." (Overcast Reb., p. 4, ll. 10-15). Having considered the full demand on capacity Dr. Overcast used the 12 monthly CP loads as part of the AED/12 CP allocation factor to determine excess demand. (Overcast Dir., p. 19, ll. 21-23, p. 20, ll. 1-7 and Overcast Reb., p. 5, ll. 13-18 and p. 6, ll. 1-6).

Dr. Overcast examined the total demand and capacity for EDE, as well as for both PSO and OG&E. According to Dr. Overcast, EDE had seven months of peak loads above 79% of peak load, while both PSO and OG&E have only four months of load above 79%. (Overcast Reb., p. 7, ll. 8-9).

For transmission, the use of 12CP is appropriate given the costs allocated to the Oklahoma retail customers are based on 12CP not 4CP. (Overcast Reb., p. 7, ll. 12-15). As suggested by Mr. Garrett, his proposal allocated lower costs to his client (higher load factor customers) and more costs to low-load factor residential customers despite the fact that the Oklahoma costs are determined on 12CP. (Tr. May 12, p. 76, l. 25 to p. 77, ll. 1-13).

The ALJ finds that use of the 12CP allocation factor for both production and transmission is a more accurate reflection of cost causation. The ALJ also finds that it is better to use more criteria than simply load as recommended by OIEC. As Dr. Overcast testified, system planners use more than customer load when they analyze the need for capacity. (Overcast Reb., p. 4, ll. 20-21). Therefore, the ALJ recommends that the Commission adopt EDE's proposed cost-of-service study including the transmission and production cost allocators.

XVIII. RATE DESIGN

EDE's proposed rate design placed an emphasis on increasing the monthly customer charge and, for those classes with demand charges, an increase to the demand charge. According to Dr. Overcast, EDE's current rates placed far too much reliance on volumetric recovery of fixed costs. Further, the current rate design did not provide EDE a reasonable opportunity to earn its allowed return in the face of events beyond the Company's control, such as weather and conservation. Third, the rates that consist of a customer charge and volumetric charge do not properly assign costs to the cost causer. Dr. Overcast further testified that current rates are not economically efficient, with the result being the inefficient use of resources resulting from incorrect price signals. (Overcast Dir., p. 29, ll. 11-18). Dr. Overcast proposed to raise the customer charge for regular residential (RG) from $12.50 per month to $20.59 per month, and the total electric residential (RH) customer charge from $12.50 to $25.00 per month. (Overcast Dir., Exhibit HEO-3, Schedule 2- Rate Design, Page 1 of 2).

AG witness Farrar recommended that the Commission reject EDE's request to increase the residential customer charge to over $20 per month. (Farrar Rate Design test., p. 6, ll. 18-21).

PUD witness Champion did not agree with the Company in its proposed rate design stating that EDE's proposal will exacerbate, for many customers, the already significant increases proposed by EDE. (Champion Rate design Resp. test., p. 11, ll. 10-11). [3]

Dr. Overcast testified that the residential customer cost, based on the historic actual test year used in the cost study, is $41.19 per customer. Even at a proposed customer charge of $20.59, and assuming that the total kWh charge is available to compensate EDE for customer costs, customers who have average use of less than 222 kWh per month do not even pay the full cost of service. The customer would not make any contribution to the fixed cost for production and transmission which is over $25.63 dollars. This essentially means that the smallest residential customers never pay the full customer costs, which theoretically results in excess customer cost being recovered in the kWh charge from larger users. (Overcast Dir. test., p. 32, ll. 14-23).

As set forth in Table 3 of Dr. Overcast's rebuttal testimony found on pages 19 and 20, the average monthly charge to a residential customer for a rural electric cooperative is $22.32. Northeast Oklahoma Electric Cooperative, Inc., which is located in close proximity to the service territory of EDE, has a monthly charge of $23.00.

The ALJ adopts the Position of PUD and AG on the customer charge. The ALJ finds that EDE's proposed customer charge would exacerbate the rate shock problem.

A. REVENUE ALLOCATION

Revenue allocation is problematic, because we start the current ratemaking with the Residential Class at a minus 1.36 RROR (PUD Schwartz, COS Resp. p. 11), while OIEC wants to move it up to 1.0 or at least to .75 (OIEC Mark Garrett, Tr. Testimony of May 12, 2017, p. 79, line 21 through p. 82), which shifts most of the revenue requirement increase to the Residential Class, causing a major rate increase to the Residential Class.

The AG recommended that the Commission make no change to EDE's cost recovery allocation among customer classes at this time. (Farrar Rate Design test., p. 6, ll. 18-20).

PUD witness Schwartz set forth PUD's proposed revenue distribution and relative rate of return on Figure 3 found on page 13 of Mr. Schwartz' cost-of-service Responsive testimony filed May 22, 2016.

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[3] The copy of the Testimony received by EDE does not have page numbers. EDE started p. 1 with the Table of Contents.

Dr. Overcast testified that revenue allocation proposed by Mr. Schwartz in his figure 3 represented a reasonable level of allocation among the classes. (Schwartz Reb. test., p. 9, ll. 19-21).

For the ALJ, the problem here is that a large percentage of the cost of providing service to the residential class is fixed, i.e. generation, transmission and distribution, while both the number of residential customers and usage by the class is declining. Nor is this situation likely to change. Empire serves the three Oklahoma counties of Craig, Delaware and Ottawa. Craig County showed a population decline of 2.7 percent from the 2010 census until July 1, 2016, while Delaware County showed over a 5 percent population drop in the same time frame. Ottawa County showed a slight population gain of 131 between the 2010 census and the end of 2015, but the recent trend is a decline from the peak in 2014. Spreading the fixed costs over a declining customer base is a two-fold problem. First, going from the current negative RROR to a positive RROR substantially increases residential rates, which is undesirable as previously explained. Next, if the Commission raises residential rates through rate design, the Commission invites degradation of EDE's winter peak load from customer migrations to propane, which in turn pushes the customer classes further out of balance. The ALJ finds that the best approach is to adopt PUD witness Kathy Champion's suggestion to allocate costs equally to all classes. Table 5 in Appendix B shows what the numbers would look like. The ALJ submits that equal split still produces residential rates that are too high. As a result, the ALJ additionally recommends adoption of some form of mitigation plan discussed below

XIX. MISCELLANEOUS PROPOSALS

A. PUD'S MITIGATION PLAN

PUD witness, Ms. Kathy Champion proposed a mitigation strategy that would implement the rate increase over a four-year period. According to Figure 1 found on page 5 of Ms. Champion's Rate Design Responsive Testimony, 30% of Staff's recommended revenue deficiency would be put in place in year one; an additional 20%, for a total of 50% of the increase, would be implemented in year two; another 25%, for a total of 75% of the increase, would be put in place in year three; and in year four the final 25% of the increase would be placed into effect, for a total of 100%, with the total customer increase being 33%. (Champion Rate Design, Figure 1, p. 6). During cross-examination, Ms. Champion testified that the Staff position was to set a new revenue requirement for each of the years during the four-year period. (Tr. May 12, p. 105, ll.1-14).

Ms. Champion added that there would need to be a true-up. According to Ms. Champion, if one has a specific revenue target per year, then there should be an opportunity to true-up to make sure that is the amount that is achieved in that year. (Tr. May 12, p. 105, ll. 14-22).

EDE's witness Mr. Timothy Lyons stated that the Company believed the proposed mitigation plan could be improved with two changes. First, the plan should recover a larger percentage of the authorized revenue increase in the first year to better balance the objectives of the mitigation plan with the Company's needs to recover its investment in a timely manner. The Company's proposed mitigation plan would implement 50% of the revenue increase in the first year. Then, there would be an additional 25% increase in year two and a final 25% increase in year three. (Lyons Reb., p. 9, ll. 10-17).

The Company also recommended that the mitigation plan should be followed by a multi-year rate plan tied to the Company's cost-of-service. According to Mr. Lyons, this approach would help ensure that ongoing changes in the Company's cost-of-service are reflected in rates on a timely basis, helping to avoid large customer bill impacts in the future. (Lyons Reb., p. 9, ll. 10-21).

Additionally, EDE recommended carrying costs on the uncollected revenues to allow the Company to recover the full amount of any rate increase granted. (Lyons Reb., p. 13, ll. 1-6). Ms. Champion's mitigation plan did not include carrying costs. As stated in EDE witness Mr. Rob Saeger's Rebuttal Testimony, by not allowing for the deferral of, and a carrying charge on, the unrecovered portion of the revenue increase, the proposed approach may result in an indirect disallowance of costs pursuant to Accounting Standards Codification ("ASC") 980-340. (Sager Reb., p. 4, ll. 1-3).

Furthermore, in considering the use of a mitigation plan, the ALJ notes that revenues associated with the SPPTC rider have been removed from determination of the overall requested deficiency. The actual level of transmission expense for the test year is reflected in the case and the Company is recommending rebasing the rider to include the current expense. (Owens/Lyons Dir., p. 6, ll. 4-10). The amount of the SPPTC rider that is being shifted from the rider to base rates is $377,214 (Owens/Lyons Dir., p. 19, l. 1), thus reducing the effective increase in revenue requirement by $377,214.

The ALJ recommends the Commission use EDE's proposed plan, because PUD's proposed mitigation plan does not grant the Company the full amount of the increase and may result in a disallowance of costs.

B. Rate Case Expense

OIEC witness Mr. Mark Garrett recommended that utilities should only be allowed to recover rate case expenses in proportion to the rate increase granted by the Commission compared to the amount of rate increase requested by the utility in its rate application. (Garrett Resp. test., p. 40, ll. 3-6).

Mr. Lyons testified that EDE did not agree with Mr. Garrett and that rate case expense is appropriate and necessary to prepare and litigate a proposed revenue increase. Further, a portion of the rate case expenses are beyond the utilities' reasonable control since a portion of rate case expense is responding to discovery requests, and analysis of the positions taken by interveners. Mr. Lyons further testified that EDE has an incentive to keep rate case expenses as low as possible since such expenses are recovered over a period of years without carrying costs. (Lyons Reb., p. 27, ll. 6-15.).

The Oklahoma Supreme Court for many years has recognized that a utility is allowed to recover rate case expense. As stated by the Oklahoma Supreme Court in *Lone Star Gas Co. v. Corporation Com'n*, 648 P.2d 36 (1982) at p. 41:

> *In Carey v. Corporation Commission*, 168 Okl. 487, 33 P.2d 788 (1934), we recognize that it would be proper for a public utility company to be allowed rate case expense when "the public service company has reasonably and fairly employed necessary outside help in connection with... (the case). Id. at 794.

There is extensive discovery from multiple parties in rate proceedings, which are beyond the control of the utility. Therefore, based upon the Supreme Court ruling quoted above and the evidence in this cause, the ALJ recommends not changing the Commission's historical method of allowing only reasonable rate case expenses, and therefore amortizes $238,000 dollars over three years without interest.

C. Multi-year Rate Plans

Mr. Lyons testified regarding the use of multi-year rate plans. According to Mr. Lyons, EDE believed that a multi-year rate plan would address several issues raised by parties in the current proceeding. Primary benefits of multi-year rate plans include helping to ensure that utility rates reflect ongoing changes in the cost of service; provide for more gradual rate changes caused by increases in plant investments (which is one of the issues in the current proceeding); produce more stable bills for customers and more stable revenues for the utilities; minimize the expense and uncertainty of rate case proceeding; and, provide incentives for the utility to manage its costs. (Lyons Reb., p. 13, ll. 7-16, p. 14, ll. 1-2).

As an example of multi-year rate plan used in Oklahoma, Mr. Lyons cited the Oklahoma Natural Gas Company's Performance Based Rate Change ("PBRC") plan, which adjusts revenues, either increases or decreases, if the earned return on equity for the most recent year falls outside of an established earned return on equity parameter. (Lyons Reb., p. 14, ll. 8-12).

According to Mr. Lyons, the purpose of the discussion of the multi-year rate plan was for the Company to introduce the concept as a possible solution around the changes in rates and the time period between rate cases. (Tr. May 10, p.m., p. 57, ll. 11-19).

The ALJ recommends the Commission encourage the parties to examine alternatives that might reduce time and costs associated with a fully litigated, contested rate proceeding, while at the same time protecting the interest of customers.

D. System Reliability

AG witness Farrar and OIEC witness Garrett both relied upon the Oklahoma Corporation Commission Regulated Electric Utilities 2016 Reliability Scorecard ("2016 Reliability Scorecard") to support their allegations that EDE provides poor service. (Garrett Resp., Exh. MG-4 and Farrar Resp., Attachment C). Mr. Garrett relies upon the 2016 Reliability Scorecard to support his recommendation to disallow 100% of short-term annual incentive plan costs from rates that are tied to operational measures such as safety, reliability and customer satisfaction. (Garrett Resp., p. 24, ll. 8-14). Mr. Farrar relies upon the 2016 Reliability Scorecard to support his recommendation "that the Commission factor in Empire's poor quality of service" as support of denying the rate increase except for the environmental compliance rider costs that were adopted by the Kansas Commission. (Farrar Resp., p. 10, ll. 3-8).

As explained in the Rebuttal Testimony of EDE witness Mr. Blake Mertens, in 2010 EDE developed a ten-year plan, referred to as Operation Toughen-Up, to construct system improvements solely to enhance the reliability of the system. (Mertens Reb., p. 1, l. 19, p. 2, ll. 1-2). Mr. Mertens described the various projects designed to improve the reliability of the Oklahoma system, as well as the accompanying dollar amounts expended on the projects. (Mertens Reb., p. 2, ll. 13-20).

According to Mr. Mertens, Oklahoma customers make up less than 3% of EDE's total customer base. However, since the inception of the reliability program, EDE has spent nearly 32% of its expenditures for the benefit of Oklahoma customers. Once the program is complete, EDE expects that approximately 14% of the total expenditures will benefit Oklahoma customers. (Mertens Reb., p. 4, ll. 7-11).

Mr. Mertens also testified that EDE does not distinguish between the States in which it provides electric service, with regards to its maintenance programs. According to Mr. Mertens, in 2008 the Missouri Public Service Commission implemented reliability inspection standards that dictated the frequency and thoroughness of the system inspections and repairs. Since the implementation of that rule, EDE has elected to implement the Missouri standards for inspection and repairs for facilities in all jurisdictions served by EDE. The Missouri rules for system inspections and repairs exceed any Oklahoma requirements for inspections and repairs. Additionally, EDE adheres to the Oklahoma vegetation management rules, which are more restrictive than those established for Missouri. (Mertens Reb., p. 4, ll. 14-22).

Mr. Mertens further testified that in order to install some of the mechanisms to improve reliability, the system was required to be put in a less reliable condition during the construction phase of the upgrades which resulted in SAIDI and SAIFI indices that are worse than what is expected at the conclusion of the overall program. (Mertens Reb., p. 5, ll. 7-13.).

Mr. Mertens testified that as EDE completes the projects described in his testimony, it expects Oklahoma's reliability metrics to improve. (Mertens Reb., p. 6, ll. 11-12).

PUD witness Mr. Jeremy Schwartz recommended the Commission reject the recommendations and/or adjustments proposed by Mr. Farrar and Mr. Garrett as they relate to system reliability. Instead, Mr. Schwartz recommended that the Commission should accept PUD's recommendation for the Company to provide an in-depth analysis of its system reliability plan in its next rate case proceeding. (Schwartz Reb., p. 10, ll. 8-12).

Mr. Schwartz discussed the Commission's rules that require electric utilities to design and maintain a reliability program. Mr. Schwartz further testified that EDE had complied with the requirements of the Commission's rules regarding the design and maintenance of a reliability program. (Schwartz Reb., p. 4, ll. 10-26, p. 5, ll. 1-22).

Mr. Schwartz also testified that during 2015 and 2016, EDE maintained its reliability levels within the Commission requirements. (Schwartz Reb., p. 6, ll. 9-11).

It is also Mr. Schwartz's testimony that adjusting the Company's revenues based on service quality could have a corresponding effect on its reliability, as it would have fewer dollars to devote to increasing its reliability levels. (Schwartz Reb., p. 9, ll. 6-8).

PUD recommends the Commission require EDE provide an in-depth analysis of its system reliability plan in its next base rate case proceeding. Such an analysis would supplement EDE's annual reliability submission to PUD and would include details on how the Company has, and would, continue to improve its reliability results. Upon review of the additional information, if the Commission is not satisfied with the results, it could make adjustments it deems necessary in the cost of service and/or rate of return of the Company at that time. (Schwartz Reb., p. 9, ll. 12-18).

Based upon the evidence in this proceeding, the ALJ does not believe that providing service, which meets or exceeds the requirements of this Commission's reliability rules, can properly be classified as "poor" service. It is clear from the testimony of Mr. Mertens, that EDE has been aware of reliability issues in its Oklahoma service territory and has developed a plan to resolve those issues. However, the ALJ does find merit with the recommendation of PUD for the Company providing a more in-depth analysis of its system reliability plan in its next general rate preceding at which time the status of operation "Toughen-Up" could be reviewed. Therefore, the ALJ recommends that the Commission reject the proposals of both Mr. Garrett and Mr. Farrar regarding system reliability and accept the recommendation of PUD witness Schwartz.

XX. CONCLUSION

All relevant, uncontested items were accepted. The foregoing findings address all capital costs and all operations and maintenance costs, which were in dispute. The ALJ's recommendations on those costs are reasonable and just. The foregoing findings provide a fair, reasonable and just rate of overall return reflecting an appropriate balance between investor and customer interests. The proposed rates recommended by the ALJ constitute the lowest reasonable rates.

Respectfully submitted

Ben Jackson

BEN JACKSON
Administrative Law Judge

6/9/17
Date

XC:
Dana Murphy
J. Todd Hiett
Bob Anthony
Teryl Williams
Nicole King
Joseph Briley
Jack P. Fite
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Thomas P. Schroedter
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APPENDIX "A"

Testimony Summaries

EMPIRE DISTRICT ELECTRIC COMPANY

THOMAS J. SULLIVAN

Direct Testimony

Thomas J. Sullivan, President and owner of Navillus Utility Consulting LLC., testified on behalf of The Empire District Electric Company ("Empire" or "Company").

Mr. Sullivan testified that a complete depreciation study was performed for Empire's plant in service on December 31, 2014, using Missouri information which was attached to his testimony.

Mr. Sullivan also sponsored the Company's proposed amortization of the depreciation reserve deficiency associated with the retirement of Riverton coal-fired generating facilities (Units 7 and 8) and Riverton combustion turbine Unit 9.

Mr. Sullivan's recommended depreciation rates for Empire's production facilities are based on the remaining life formula, and the depreciation rates for all other facilities (mass property accounts) are based on the whole life formula. Mr. Sullivan also recommended that Empire amortize the undepreciated portion of its investment in the recently retired Riverton steam Units 7 and 8 and Riverton combustion turbine Unit 9 and the cost of decommissioning Riverton Units 7, 8, and 9 over a five-year period.

Mr. Sullivan testified that a five-year amortization of the undepreciated portion of Empire's investment in Riverton Units 7 and 8 and the decommissioning costs associated with the Riverton Units 7 and 8 are equal to $2,135,793 annually, and the undepreciated portion of Empire's investment in Riverton Unit 9 and its associated decommissioning costs are equal to $162,898 annually.

Regarding Riverton Units 7 and 8 coal-fired steam generation units, Mr. Sullivan testified that at the time these units were retired by Empire in June 2015, there was a negative reserve of $6.8 million which represents the undepreciated investment in these units. The units have not been depreciated by Empire since their retirement in June 2015. In addition, Empire has received estimates that it will cost $3.9 million to decommission the units. Therefore, there is a total cost of $10.7 million left to be recovered from the Riverton Units 7 and 8.

Mr. Sullivan recommended that these costs be amortized over a five-year period beginning with the effective date of new rates resulting from this case. The $10.7 million remaining cost, when amortized over 5 years, results in an annual amortization of $2,135,793.

According to Mr. Sullivan, Riverton Unit 9 was retired in June 2015. At the time of its retirement, Unit 9 had $758,397 in undepreciated investment. In addition, the same decommissioning study for Riverton Units 7 and 8 includes approximately $56,000 in net decommissioning costs for Riverton Unit 9. Mr. Sullivan recommended that these costs also be amortized over a five-year period beginning with the effective date of new rates resulting from this case. The $814,490 remaining cost, amortized over 5 years, results in an annual amortization of $162,898.

Mr. Sullivan testified that in his opinion, it is always preferable to recover costs from the ratepayers who are receiving the benefits of the facilities. Deferring costs beyond the retirement of the assets can result in an inter-generational subsidy. In other words, current and future ratepayers will pay costs that should have been borne by past ratepayers. However, Empire is entitled to full recovery of these assets, and the 5-year amortization is a reasonable timeframe to recover the investment and yet mitigate the potential inter-generational subsidy.

Further, the use of the remaining life formula for unit assets (such as power plants) should be used instead of the current practice of using the whole life formula. The remaining life formula and the ability to adjust depreciation rates periodically will provide a more reasonable and straightforward basis to recover the cost of these assets over their useful life.

Mr. Sullivan's depreciation rates for production facilities were developed using the life span and unit property approaches underlying Empire's existing rates. According to Mr. Sullivan, the Riverton steam Units 7 and 8; combustion turbine Unit 9, combustion turbines Units 10 and 11; and combined cycle Unit 12, are treated as separate unit properties. Also, Iatan Units 1 and 2 are treated as separate unit properties.

Mr. Sullivan explained why the remaining life formula is preferable. According to Mr. Sullivan, the remaining life formula for unit property accounts provides a much better opportunity to recover the investment in the facility over the asset's useful life and avoids the situation of deferring cost recovery beyond the life of the unit asset, thus resulting in inter-generational subsidy. The basic premise of the whole life method is that one straight-line depreciation rate is used over the entire life of the asset. If the life characteristics of an asset change over the life of that asset, or if additions are made to an asset that have a lifespan less than the whole life of the plant, depreciation rates based on the whole life method tend to have a bias towards under-collecting depreciation expense, especially for unit type properties such as power plants. If this bias is not corrected, the end result is a failure to properly recover the cost of the unit asset over its useful life.

While the whole life formula can be adjusted for reserve deficiencies (or excesses) to essentially mirror the remaining life formula, it is much more straightforward to use the remaining life formula. For new facilities, the remaining life and whole life formulae produce essentially the same answer, as shown in Table 5-1 for the Iatan and Plum Point units. The issues with using whole life rates over the entire life of an asset begin to manifest themselves as units age and the life of the plant is changed (usually due to life extending investments) and as investments are made to the plant throughout its life that have service lives less than the entire life of the facility.

Mr. Sullivan further testified that the retirement dates and resulting lifespan for Asbury 1 had been increased by 5 years, from a 60 year lifespan (in the 2010 Depreciation Study) to a 65 year lifespan. The retirement date and resulting lifespan for Iatan 2 was increased by 10 years, from a 50 year lifespan (in the 2010 Depreciation Study) to a 60 year lifespan. The 60 year lifespan is consistent with the lifespan being used by Kansas City Power & Light Company, the majority owner of the plant.

For the combustion turbine units Energy Center 1 and 2, Riverton 10 and 11, and State Line 1, the retirement dates and lifespans were reduced by 5 years, from 50 years to 45 years. For the FT-8 combustion turbine units Energy Center 3 and 4, the retirement dates and lifespans were reduced by 10 years, from 50 years to 40 years.

Mr. Sullivan developed rates for the mass property accounts by using the whole life formula underlying Empire's existing rates. The mass property accounts include all transmission, distribution, and general plant facilities and equipment.

According to Mr. Sullivan, the primary reason is that this is the methodology historically used in Missouri and it is the basis for Empire's existing depreciation rates. In addition, there are several key distinctions between the mass property accounts and the unit property accounts. Generally speaking, mass assets do not have a unique or distinct identity. In other words, one transformer, meter, or piece of conductor (of given capacities) is not much different from another and, when a unit is retired, it is usually replaced with a very similar unit with similar life characteristics. Further, the service provided by the mass asset group has an indefinite lifespan, even though individual units have a finite life. If a meter at a home breaks or wears out, it is replaced with another meter that provides essentially the same function and the service continues. This is the key distinction between a mass property unit like a meter or transformer and a unit property like a power plant.

Mr. Sullivan further testified that a power plant has a finite life and, as the end of that life approaches, the specific date of retirement becomes more certain. Once that power plant is retired, it is not immediately replaced with a similar unit. Power plants are large facilities that take years to plan and construct. When Empire retired the 38 megawatt Riverton 7 coal-fired steam unit, it did not replace it with another 38 megawatt coal-fired steam unit.

Mr. Sullivan recommended the following:

1. Adopt the remaining life rates shown in Column E of Table 5-1 in Schedule TJS-2 for Empire's production facilities;
2. Adopt the whole life rates shown in Column O of Table 6-1 in Schedule TJS-2 for Empire's mass property accounts; and,
3. Adopt the amortization of the undepreciated plant investment and decommissioning costs associated with the Riverton steam units (Units 7 and 8) and Riverton combustion turbine Unit 9 shown in Table 5-5 of Schedule TJS-2 over a five-year period beginning with the conclusion of this rate case.

<u>Rebuttal Testimony</u>

Mr. Sullivan filed rebuttal testimony to PUD Witness Mr. Thompson, AG Witness Mr. Farrar and OIEC Witness Mr. David Garrett.

Mr. Sullivan disagreed with OIEC witness David Garrett's recommendations to amortize the undepreciated portion of the retired Riverton Units 7, 8, and 9 over 42 years. According to Mr. Sullivan, Mr. Garrett asserts that since "the retirement of Riverton 7, 8, and 9 and the conversion of Riverton 12 were part of the same environmental plan" (Page 33, Lines 14 and 15) and because "future customers, not current customers, who are the primary beneficiaries of the environmental compliance plan" (Page 34, Lines 2 through 3), the amortization period should be equal to the remaining life of the Riverton 12 plant.

Mr. Sullivan testified that there were several flaws with Mr. Garrett's logic. First and foremost, as discussed in his direct testimony, the five-year period he recommend was intended to strike a balance 1) between the fact that the cost of Riverton Units 7, 8 and 9 were not recovered over their useful life because the depreciation rates used were too low, and 2) recovering those costs over a reasonable period of time to mitigate inter-generational subsidies. Second, the Riverton Units 7, 8 and 9 were placed in service in 1950, 1954, and 1964, respectively, and were nearing the end of their useful lives regardless of the environmental compliance plan. Mr. Garrett's recommendation would create a depreciation and amortization period of 109 years for Riverton Unit 7, 105 years for Unit 8, and 95 years for Unit 9. Third, Mr. Garrett's testimony inaccurately implies that the environmental compliance plan was the only driver for the retirement of Riverton Units 7, 8 and 9. Fourth, there are other generating units that were also part of the environmental compliance plan; Mr. Garrett appears to have simply chosen the power plant with the expected retirement date that is directly under the Company's control that is the furthest in the future. For these reasons, the OIEC's recommendation is unreasonable and should not be adopted by the Commission.

According to Mr. Sullivan, the OIEC is essentially proposing the following three adjustments or changes to the depreciation rates he recommended for Empire's production facilities:

1. The OIEC proposes to use the lifespans that OIEC assumes are underlying the Company's existing depreciation rates.
2. The OIEC proposes to include no allowances for cost of removal or salvage to be included in the derivation of the Company's depreciation rates for its production facilities.
3. The OIEC includes no allowance for interim activity (over the remaining life) in the determination of the Company's depreciation rates for its production facilities.

According to Mr. Sullivan, Mr. Garrett appears to imply that the "currently approved lifespans of the production units" should be used in lieu of the lifespans recommended by Mr. Sullivan. Mr. Garrett lists several instances where Mr. Sullivan reduced the lifespans on some units that were reduced relative to the lifespans that were recommended in Mr. Sullivan's 2010 Report.

Mr. Sullivan testified that Mr. Garrett did not accurately portray the lifespan changes recommended in Schedule TJS-2 relative to the 2010 report.

Mr. Garrett's discussions on Page 18 only highlight the changes made to the Company's combined cycle and combustion turbine generating units where Mr. Sullivan generally reduced the lifespans. However, Mr. Garrett fails to mention that Mr. Sullivan recommended increasing the lifespans on Asbury and Iatan 2 (based on aligning the retirement date of Iatan 2 with the expected retirement date used by Kansas City Power & Light Company – the majority owner and operator).

The lifespans proposed by Mr. Garrett are not based on "currently approved lifespans" according to Mr. Sullivan.

The estimated retirement date used by Mr. Garret for Asbury appears to be 2035 which is the same date recommended by Mr. Sullivan. Mr. Sullivan recommended an increase in the retirement date from 2030 to 2035. The estimated retirement date used by Mr. Garrett for Iatan 2 is also the same as the retirement date used by Mr. Sullivan which was an increase in the retirement date from 2060 to 2070.

Mr. Sullivan testified that as indicated in the Company's response to OIEC Data Request 2.1 and 6.1, the current depreciation rates for Empire's production facilities are not based on a lifespan methodology. The current rates are based on a settlement in Missouri Case No. ER-2011-004. The Settlement adopted the depreciation rates proposed by the Missouri PSC Staff which are based on a whole life mass property approach that does not consider the retirement dates of the individual generating units.

Mr. Sullivan testified that contrary to what he says in his direct testimony, Mr. Garrett has actually cherry-picked between the lifespans used in Schedule TJS-2 and those used in Mr. Sullivan's prior study (2010 Report), not the currently approved lifespans as he states. In cases where Mr. Sullivan has increased the lifespans in Schedule TJS-2 relative to the 2010 Report, he uses the longer lifespans in Schedule TJS-2. In cases where Mr. Sullivan had reduced the lifespans in Schedule TJS-2 relative to the 2010 Report, he uses the longer lifespans in the 2010 Report.

The prior question lists the generating units where he uses the longer lifespans in Schedule TJS-2, the following are where he uses the longer lifespans in the prior 2010 Report:

1. Energy Center 1 and 2 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, 2023 and 2026 retirement dates, respectively. In his 2010 Report, he recommended retirement dates of 2028 and 2031. Mr. Garrett uses a retirement date of 2031 for both units.

2. Energy Center 3 and 4 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 40 year life, a 2043 retirement date for both units. In Mr. Sullivan's 2010 Report, he recommended retirement dates of 2053 for both units. Mr. Garrett uses a retirement date of 2053.

3. Riverton 10 and 11 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, a 2033 retirement date for both units. In his 2010 Report, he recommended retirement dates of 2038 for both units. Mr. Garrett uses a retirement date of 2038 for both units.

4. Stateline 1 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, a 2040 retirement date. In his 2010 Report, he recommended a retirement date of 2045. Mr. Garrett uses the 2045 retirement date.

For the other units not mentioned, he made no changes between Schedule TJS-2 in his 2010 Report.

Mr. Sullivan further testified that on Page 18, Lines 9 through 10, Mr. Garrett states that "Mr. Sullivan, however, provided no other analysis, documentation, or support for the proposed lifespan decreases." This statement is misleading on a couple of fronts. First, it fails to indicate that Mr. Sullivan also recommended lifespan increases set forth above. Furthermore, all of the lifespans Mr. Garrett recommended are based on Mr. Sullivan's recommendations from either Schedule TJS-2 or his 2010 Report (and not based on currently approved lifespans as Mr. Garrett asserts, as there are none because the settlement was not based on a lifespan methodology) and Mr. Sullivan essentially provided the same support and/or rationale for both sets of lifespan recommendations. The recommendations in TJS-2 are based on more current expectations; that is the only real difference between the two sets of numbers.

According to Mr. Sullivan, The OIEC is using a zero net salvage allowance. While Mr. Garrett's testimony on Pages 13 through 16 only discusses terminal net salvage, in fact, the OIEC has not included any salvage or cost of removal allowance on interim or final retirements. In his testimony, Mr. Garrett appears to confuse salvage and cost of removal associated with interim retirements (retirements that occur over the life of the asset) and final or terminal cost of removal and salvage associated with the decommissioning of the power plant. However, the OIEC's recommendations are not limited to terminal net salvage but rather reflect no cost of removal or salvage allowances at all.

Mr. Sullivan testified that the OIEC did not accurately characterize the net salvage allowances he used in the development of the depreciation rates he recommended for the Company's production facilities and his responses to their data requests.

On Page 15, Lines 6 through 8, Mr. Garrett asks and answers the following:

"Q. Did Empire provide any other adequate support for its proposed terminal net salvage rates?

A. No. When asked in discovery to provide all justification and support for the proposed net salvage rates, Mr. Sullivan states that the proposed net salvage amounts "represent minimal allowances that we deem reasonable absent specific demolition studies".

In fact, the above question and answer are a complete fabrication achieved by cutting and pasting three different answers to three different data requests regarding two separate and distinct issues.

In Schedule TJS-3, Mr. Sullivan provided copies of his responses to OIEC data requests 2.14, 4.2, and 9.1.

In data request 2.14, the OIEC asked for all decommissioning studies Mr. Sullivan relied upon. In his response, he indicated that the only decommissioning studies relied upon were for Riverton 7, 8 and 9. Mr. Garrett's discussion on Pages 13 through 16 of his direct testimony did not pertain to Riverton 7, 8 and 9, because neither the OIEC nor the Company recommended depreciation rates for Riverton 7, 8 and 9 since these units are retired. Thus, nowhere in Mr. Sullivan's recommended depreciation rates for the Company's production units did he include any allowance for terminal net salvage.

In Mr. Sullivan's response to OIEC data request 4.2, his response clearly stated that the Company did not include any terminal net salvage in our determination of the depreciation rates for the Company's production units. The response clearly states that: "All net salvage rates for production accounts are for interim retirements".

Finally, in Mr. Sullivan's response to OIEC data request 9.1, he indicated what net salvage allowances he used for interim retirements, having previously established through OIEC data request 4.2 that all salvage rates were for interim retirements. The last sentence that is quoted in Mr. Garrett's testimony is taken completely out of context. The last sentence is properly interpreted to mean that the Company used minimal allowances (for interim retirements only), and when taken in the context of the other two data requests, Empire did not use any terminal net salvage unless there were specific demolition studies (as was the case for Riverton 7,8 and 9).

Mr. Sullivan testified that OIEC's recommendation regarding net salvage for the production facilities was not reasonable.

First, Mr. Garrett's testimony does not address the actual net salvage amounts Mr. Sullivan recommended. He is actually discussing a fabrication of a terminal net salvage recommendation that does not exist. The actual net salvage allowances Mr. Sullivan had reflected are minimal allowances that he deemed reasonable for interim cost of removal and salvage. The adjustment for terminal net salvage that Mr. Garrett actually makes relative to Mr. Sullivan's recommendation is to remove minimal allowances for interim activity for which he provides no justification in his testimony. Mr. Garrett provides justification for removing an adjustment that does not exist.

Mr. Sullivan further testified that on Page 17, Lines 3 through 10 of his direct testimony, Mr. Garrett's response to his question again tries to cleverly combine unrelated statements to create the appearance of something that is simply not there. First, the question between Lines 2 and 3 asks: "Is the cost recovery of plant that has not been deemed prudent or "used and useful" appropriate?" Nowhere in Mr. Sullivan's analyses did he advocate the recovery of investment through depreciation expense for plant that is not in service. Yet, Mr. Garrett's response essentially acknowledges that the question creates a premise that is not true because his response to this question actually answers a different question than the question he poses. On Page 17, Lines 6 through 8, Mr. Garrett states: "Mr. Sullivan's proposed depreciation rates for the Company's production accounts mathematically incorporate these unapproved future plant additions." While this statement is also not accurate, nowhere does Mr. Garrett say (because it is patently not true) that Mr.Sullivan recommended that depreciation expense be calculated based on plant that is not yet in service. Yet, his question insinuates this false premise.

According to Mr. Sullivan, the analyses contained in Appendix A of Schedule TJS-2 show the detailed calculation of the depreciation rates he recommended for Empire's production facilities. They do not show the calculation of depreciation expenses. This analysis includes the historical additions and retirements by account for each generating unit property as well as forecasts of future additions and retirements based on this historical experience. The purpose of this analysis is to estimate the amount of plant balance that would be available each of the remaining years such that a true straight line depreciation rate can be determined that will depreciate all the investment in the facility as (and only as) that investment is actually made.

Mr. Sullivan testified that the failure to consider the impact of future interim retirements and additions results in depreciation rates that are low during the early years of the generating units' lifespan and higher during the later years. This happens primarily for the following reasons:

1. Failure to recognize that many of the component assets have an average service life that is less than the entire lifespan of the generating units.

2. Failure to recognize that capital improvements that are made after the initial in-service date of the asset will have service lives that are less than the entire lifespan of the generating units.

3. Failure to recognize that in order for the generating units to achieve the relatively long lifespans historically experienced, significant capital improvements are made to extend the assets' life and/or to bring the units up to current technology and regulations such that the plants can continue to economically provide service. These relatively large capital additions usually have service lives much less than the lifespan of the generating unit.

Mr. Sullivan testified that it is clearly demonstrated in the existing depreciation rates for Empire's steam production units as shown in Schedule TJS-2. The lowest current depreciation rate is 2.10 percent for Iatan II (put in service in 2010) which is Empire's newest steam production unit. Plum Point (2010) is roughly the same age but has a shorter estimated life, so its current depreciation rate is 2.33 percent. Iatan 1 (1980) is the next oldest unit and is significantly older than Iatan 2 and it has a current depreciation rate of 3.12 percent. The Company's oldest steam production unit is Asbury (1970) and it has a depreciation rate of 4.73 percent. Asbury best demonstrates the phenomena Mr.Sullivan discussed above as shown on Page A-6 of the Depreciation Study (Schedule TJS-2).

The net effect is loading most of the depreciation expense near the end of, and even beyond, the useful life of the generating unit. This creates a huge disconnect between the recovery of the cost of the facility and the value received by the customers who most benefit from the facility. This is further exacerbated when one also takes into account that base load generating units tend to be used less and less as they approach the end of their useful life because newer units tend to be more efficient and economical to dispatch, and are therefore utilized more.

Mr. Sullivan testified that his recommended method did not accelerate depreciation expense accrual.

As Schedules TJS-4 and TJS-5 demonstrates, the deprecation accrual rates are stable throughout the entire service life of the asset.

Mr. Sullivan further testified that his recommended method did not result in mathematically collecting depreciation expense on future costs that are not in service and used and useful.

The depreciation rates are applied to the current period actual plant in service balance, the same balance as the depreciation rates developed using the OIEC's approach. There are not any future dollars in the calculation of depreciation expense (depreciation rate times current plant in service balance).

As shown in Section I, Schedule 2 of the Company's revenue requirement model, the depreciation rates are multiplied by plant balances at June 30, 2016, which do not include the interim additions and retirements used in the development of the depreciation rates.

According to Mr. Sullivan, while there is still higher depreciation expense at the end of the asset's life using the approach he is recommending, a more stable depreciation rate results if forecasted interim retirements and additions are included in the determination of the depreciation rate than if they are not included. The approach he is recommending is a reasonable compromise between the OIEC's approach which defers significant amounts of depreciation expense to the later years of (and even beyond) the generating facility's life, and a unit of production approach which would seek to directly match the investment in the facility with the use (i.e. output) of the facility.

The interim retirements and additions he included are only based on historical experience excluding large capital projects. For the newer base load units such as Iatan 2 and Plum Point, there is virtually no way these units are going to be in service in 2070 and 2060, respectively, without large capital improvements (that will have much shorter remaining lives) than what has been reflected in Schedule TJS 2. As such, the depreciation rates for these units will increase significantly if these plants are still in service that far into the future.

Mr. Sullivan testified that if the Commission were to disallow interim retirements and additions, then the plant lives should be shortened. It is not proper to accept the extra life of the plant due to the interim additions while ignoring the cost of those additions. Both need to either be included or both excluded or the depreciation rate will not match the use of the power plant.

As stated on Pages 6-38 through 6-39 of Accounting for Public Utilities:

> "A depreciation study attempts to predict the future. Therefore, these studies endeavor to consider the estimated effects of future events, of which power plant life extension projects are examples. Such projects have two aspects that are linked:
>
> 1) the capital expenditures made to accomplish life extension; and
> 2) the extra life that is the direct result of these expenditures.

Deferral of recording and recovery of depreciation will occur if the link between these two aspects is broken by elimination from the depreciation rate calculations the capital expenditures until they are recorded in plant-in-service, but currently included in the extra life resulting from the expenditures. Because some of the rate calculation components become inconsistent, depreciation rates will initially decrease and will later increase as the expenditures are made and the rates are recalculated. Increasing depreciation rates for power plants are not rational because they do not match the consumption or usage of the underlying asset."

Mr. Sullivan continued his rebuttal by testifying that beginning on Page 16, Line 13 and continuing onto Page 17, Mr. Garrett states that he has never seen depreciation rates for production units calculated the way he had calculated them in Appendix A of Schedule TJS-2. The testimony filed in the Company's last Oklahoma rate case in Cause No. PUD 201100082 included the 2010 Report discussed earlier in this rebuttal testimony. This report uses the same methodology used in Schedule TJS-2.

Prior to starting his own company in 2011, Mr. Sullivan worked for over 30 years for Black & Veatch Corporation. The first depreciation study he worked on for Black & Veatch was in the late 1980's for Black Hills Power and Light Company and it incorporated this same methodology. This methodology was developed coincident with the widespread use of personal computers. The senior experts at Black and Veatch at that time determined that developing a more transparent analysis of unit properties for which a finite retirement date was known was preferable to using what, up until that time, was largely done in a black box program by mainframe computers. While many of those programs have been converted to use on personal computers, they still lack the flexibility and transparency of performing the calculations using a spreadsheet analysis. Thus the methodology used in Appendix A of Schedule TJS-2 has been the standard practice at Black & Veatch since the 1980's.

Mr. Sullivan testified that there were two significant problems with the OIEC's mass property accounts analyses. First, OIEC excluded historical data from their analyses even though the OIEC claims its analyses are based on all the historical data. The result of excluding this data artificially skews the OIEC's results towards longer service lives. Second, the OIEC mischaracterizes the analyses Mr. Sullivan performed by mismatching his recommended Iowa curves to the abbreviated datasets used in their analyses thus leading one to conclude that his results do not match the underlying data used (which includes all the Company's historical data).

On Page 20, Lines 11 and 12, Mr. Garrett states: "I used all of the Company's property data and created an observed life table ("OLT") for each account."

Mr. Sullivan testified that statement was not correct. In fact, Mr. Garrett has truncated the placement and experience bands of the data he presented in his testimony and exhibits. This is most evident by the fact that none of the accounts in Exhibits 2-6 through 2-17 have exposures older than 55 years, yet Empire's continuing property records contain data as far back as 1900.

According to Mr. Sullivan, the following are the accounts which Mr. Garrett identified as material and the full data available for each account:

1. Account 353 – 1900 to the present
2. Account 362 – 1912 to the present
3. Account 364 – 1900 to the present
4. Account 369 – 1926 to the present
5. Account 390 – 1903 to the present

Mr. Garrett's analysis begins with data from 1960 to the present, not "all of the Company's property data". In addition to the accounts listed above, there are several others where Mr. Garrett has used something less than the full set of data available.

Mr. Sullivan testified that the OIEC had mischaracterized the analyses he performed by mismatching Mr. Sullivan's recommended Iowa curves to the abbreviated datasets used in OIEC's analyses.

In Figures 2 through 6 of his testimony, Mr. Garrett claims he is comparing the Company's selected Iowa curve, the OIEC's selected Iowa curve, and the OLT (Observed Life Table) curve, which as Mr. Sullivan indicated earlier he claimed includes all of the Company's property data. First, his analyses did not use all of the Company's property data. Second, the

OIEC graphs are further truncated at 50 percent surviving. Third, the Company analyses Mr. Garrett shows are based on the Iowa curves shown in Mr. Sullivan's Schedule TJS-2 which do include all of the Company's property data. By making these apples and oranges comparisons, Mr. Garrett's figures mislead the reader into believing that his selected curves fit all of the Company's data better than the curves Mr. Sullivan used, when in fact they do not. His curves fit the truncated (1960 to present) data better. Nowhere in his testimony does Mr. Garrett make this critical distinction. In Mr. Sullivan's workpapers, he provided analyses using both the full data sets and also a test against the 1960 to present shortened data set, but his recommended Iowa curves are based on the full data sets available.

Mr. Sullivan prepared curves showing how his selected curves actually fit all the Company data.

These curves are included in Schedule TJS-6. This schedule shows that the curves Mr. Sullivan recommended fit all of the data better than the curves selected by the OIEC.

In response to a question of what was the net effect of the OIEC using the abbreviated data set, Mr. Sullivan testified that there were two impacts that bias the results towards producing longer lives. By Mr. Garrett removing the older plant and focusing on only the top half of the survivor curve (100% to 50% surviving), he has stretched out the curve by removing the tails of the curve and by removing plant that has gone through its full life cycle. Mr. Sullivan stated that it needed to be made clear that the mathematical analyses underlying his analyses and the OIEC's are essentially the same, a least squares or best fit analysis comparing actual data to standardized Iowa curves. The only difference results from using different data band; the full data band versus the truncated data band. The OIEC has not used all of the Company's data as it claims it has used.

In response to AG witness Farrar, Mr. Sullivan testified that on Page 11, beginning at line 2, Mr. Farrar states that Empire's proposed depreciation rates should be rejected because "future additions to plant were included in the filed depreciation study". Mr. Sullivan assumed Mr. Farrar was referring to interim additions which he addressed in his rebuttal testimony.

He disagreed that consideration of the effective interim activity on the calculation of depreciation rates is an "inappropriate rate making policy". If one excludes the expenditures one must also exclude the extra life which is a result of those expenditures. To not do so would certainly be inappropriate rate making policy.

Mr. Sullivan testified that the depreciation rates recommended in Schedule TJS-2 (based on total Company plant in service at June 30, 2015) resulted in a reduction in depreciation expenses of $198,726 for transmission plant, a reduction in depreciation expenses of $3,654,194 for distribution plant, and an increase in depreciation expenses of $68,859 for general plant. The reductions in depreciation expenses for transmission and distribution plant resulted primarily from recommending longer lives than the lives underlying the existing depreciation rates.

According to Mr. Sullivan, the depreciation rates were reviewed by the Missouri Public Service Commission Staff in Docket No. ER-2016-0023. For the mass property accounts, the Missouri Public Service Commission Staff's findings were so close that he did not even bother to rebut them in that case. Further, the Staff's overall recommendation on the mass property accounts was for generally shorter lives than Mr. Sullivan recommended.

Mr. Sullivan concluded by stating the OIEC's testimony and exhibits are based on misrepresentations and unreasonable and inaccurately supported recommendations. The AG's recommendation is contrary to sound depreciation theory. Therefore, neither should be relied upon by the Commission.

DR. JAMES H. VANDER WEIDE

Direct Testimony

Dr. James H. Vander Weide, President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients, testified on behalf of Empire.

Dr. Vander Weide testified that he estimated Empire's cost of equity by applying several standard cost of equity methods to market data for a large proxy group of electric utility companies.

According to Dr. Vander Weide, he applied his cost of equity methods to a large group of comparable risk companies because standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies; and thus, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the principle enunciated by the United States Supreme Court that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk (*see Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 561, 603 (1944)).

Dr. Vander Weide testified that on the basis of his studies, he found that the cost of equity for his proxy companies is in the range 9.3 percent to 10.5 percent, with an average equal to 9.9 percent. This conclusion was based on his application of standard cost of equity estimation techniques, including the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities, and on the evidence he presented in his testimony that the CAPM, as typically applied, significantly underestimates the cost of equity for companies such as his proxy companies with betas significantly less than 1.0.

He recommended that Empire be authorized a rate of return on equity equal to 9.9 percent.

According to Dr. Vander Weide, his recommended 9.9 percent return on equity is conservative because it does not reflect the higher financial risk implicit in the Company's ratemaking capital structure compared to the average financial risk of the proxy companies' market value capital structure. The financial risk of the proxy companies depends on the market values of the debt and equity in the companies' capital structures.

According to Dr. Vander Weide, economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. If investors do not expect to earn a return on their investment in a company or project that is at least as large as the return they expect to receive on other investments of comparable risk, rational investors will not invest in the company or project.

Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have only a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

According to Dr. Vander Weide economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as he noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Dr. Vander Weide testified that investors estimate the expected rate of return in several steps. First, they estimate the amount of their investment in the company. Second, they estimate the timing and amounts of the cash flows they expect to receive from their investment over the life of the investment. Third, they determine the return, or discount rate, that equates the present value of the expected cash receipts from their investment in the company to the current value of their investment in the company.

Dr. Vander Weide further testified that investors generally measure investment risk by estimating the probability, or likelihood, of earning less than the required return on investment. For investments with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Dr. Vander Weide explained that business risk is the underlying risk that investors will earn less than their required return on investment when the investment is financed entirely with equity. Financial risk is the additional risk of earning less than the required return when the investment is financed with both fixed-cost debt and equity.

He further testified that the business risk of investing in electric utility companies such as Empire is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

With regard to regulatory uncertainty, Dr. Vander Weide also testified that investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation. Investors are keenly aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Dr. Vander Weide testified that the risks of investing in electric utilities such as Empire can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in electric utilities are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are largely irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in electric utilities such as Empire are largely asymmetric. That is, there is little opportunity for the utility to earn more than its required return, but a significant chance that the utility will earn less than its required return.

Dr. Vander Weide testified that he used several generally accepted methods for estimating the cost of equity for Empire. These are the Discounted Cash Flow (DCF), the ex ante risk premium, the ex post risk premium, and the capital asset pricing model (CAPM). The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The ex ante risk premium method assumes that an investor's current expectations regarding the equity risk premium can be estimated from data on the DCF expected rate of return on equity compared to the interest rate on long-term bonds. The ex post risk premium method assumes that an investor's current expectations regarding the equity-debt return differential is equal to the historical record of comparable returns on stock and bond investments. The cost of equity under both risk premium methods is then equal to the interest rate on bond investments plus the risk premium. The CAPM assumes that the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

In regard to Dr. Vander Weide's DCF study, Dr. Vander Weide explained that the DCF equation requires estimates of the growth, dividend, and price terms. As his estimate of growth in his DCF model, Dr. Vander Weide used the analysts' estimates of future earnings per share ("EPS") growth reported by I/B/E/S Thomson Reuters. Dr. Vander Weide explained that he used the I/B/E/S growth estimates because his studies indicate that analysts' forecasts are the best estimate of investors' expectation of future long-term growth, and the DCF model requires the growth expectations of investors. Dr. Vander Weide also described his statistical study comparing historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. He noted that researchers at State Street Financial Advisors updated his study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

As his estimate for the price term, Dr. Vander Weide used a simple average of the monthly high and low stock prices for each firm for the three-month period ending October 2016. These high and low stock prices were obtained from Thomson Reuters. Dr. Vander Weide testified that he used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

He further testified that because Empire is seeking to recover its equity flotation costs as an expense over a five-year period, he did not include an allowance for flotation costs in his cost of equity calculations.

He applied the DCF approach to the Value Line electric companies shown in his Schedule JVW-1.

He selected all the companies in Value Line's groups of electric companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have an I/B/E/S long-term growth forecast; and (4) are not the subject of a merger offer that has not been completed. In addition, each of the utilities included in his comparable groups had an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3.

Dr. Vander Weide obtained an average DCF result of 9.3 percent for his proxy company group.

Dr. Vander Weide also employed the risk premium approach to estimate Empire's cost of equity, using two risk premium methods, an ex ante risk premium approach and an ex post risk premium approach. As Dr. Vander Weide explained, the risk premium method is based on the principle that investors expect to earn a return on an equity investment in Empire that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Dr. Vander Weide's ex ante risk premium method is based on studies of the DCF expected return on a proxy group of electric companies compared to the interest rate on Moody's A-rated utility bonds. Dr. Vander Weide performed a regression analysis to determine if there is a relationship between the calculated risk premium and interest rates and uses the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity using the ex ante risk premium method, according to Dr. Vander Weide, one may add the estimated risk premium over the yield on A-rated utility bonds to the forecasted yield to maturity on A-rated utility bonds. He obtained the expected yield to maturity on A-rated utility bonds, 5.8 percent, by averaging the most recent forecast data from Value Line and the U.S. Energy

Information Administration ("EIA"). For his electric utility sample, his analyses produced an estimated risk premium over the yield on A-rated utility bonds equal to 4.7 percent. Adding an estimated risk premium of 4.7 percent to the expected 5.8 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.5 percent using the ex ante risk premium method.

Dr. Vander Weide described in detail his ex post risk premium method for measuring the required risk premium on an equity investment in Empire.

Dr. Vander Weide concluded that his ex post risk premium analyses provide evidence that investors today require an equity return of at least 3.9 to 4.5 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.8 percent. Adding a 3.9 to 4.5 percentage point risk premium to a yield of 5.8 percent on A-rated utility bonds, he obtained an expected return on equity in the range 9.7 percent to 10.3 percent, with a midpoint estimate equal to 10.0 percent.

Dr. Vander Weide stated that the CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

According to Dr. Vander Weide, the CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For his estimate of the risk-free rate, he used the forecasted yield to maturity on 20-year Treasury bonds of 4.45 percent, using forecast data from Value Line and EIA.

For his estimate of the company-specific risk, or beta, he used the average 0.72 Value Line beta for his proxy electric companies and the 0.90 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio.

For his estimate of the expected risk premium on the market portfolio, he used two approaches. First, he estimated the risk premium on the market portfolio using historical risk premium data reported in the 2016 Valuation Handbook for the years 1926 through 2015, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, he estimated the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Dr. Vander Weide concluded that based on his application of several cost of equity methods to his proxy companies, his proxy companies' cost of equity is in the range 9.3 percent to 10.5 percent, with an average result equal to 9.9 percent. Dr. Vander Weide provided the following table:

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT
Discounted Cash Flow	9.3%
Ex Ante Risk Premium	10.5%
Ex Post Risk Premium	10.0%
CAPM-Historical	9.7%
CAPM-DCF Based	10.2%
Average	9.9%

Dr. Vander Weide testified that his cost of equity conclusion reflects the financial risk associated with the average market value capital structure of his proxy companies, which has approximately 64 percent equity.

Empire is recommending that its consolidated capital structure containing approximately 49.68 percent common equity be used for rate making purposes in this proceeding.

According to Dr. Vander Weide, although Empire's recommended capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for rate making purposes in this proceeding, this recommended rate making capital structure embodies greater financial risk than is reflected in his cost of equity estimates from his proxy companies.

Dr. Vander Weide testified that he conservatively recommends an ROE equal to 9.9 percent. This recommendation is conservative in that it does not reflect the higher financial risk implicit in Empire's rate making capital structure compared to the average financial risk of the proxy companies implicit in the values of debt and equity in their market value capital structures.

<u>Rebuttal Testimony</u>

Dr. Vander Weide filed rebuttal testimony to respond to the allowed rate of return on equity and cost of equity recommendations of Mr. David J. Garrett ("OIEC") and Mr. Geoffrey M. Rush ("PUD").

Mr. Garrett recommended an allowed return on equity equal to 9.0 percent, and Mr. Rush recommended an allowed return on equity equal to 9.9 percent. Mr. Garrett estimated a cost of equity equal to 7.5 percent, and Mr. Rush estimated a cost of equity equal to 7.91 percent. According to Dr. Vander Weide, there was nothing in these testimonies that would cause him to change his cost of equity recommendations.

Dr. Vander Weide testified that Mr. Garrett arrived at his recommended 9.0 percent recommended ROE by: (1) estimating that Empire's cost of equity is 7.5 percent; (2) noting that Empire's current allowed ROE is 9.9 percent; and (3) recommending that the Commission gradually reduce Empire's current 9.9 percent allowed return on equity to his 7.5 percent estimate of Empire's cost of equity. In Mr. Garrett's opinion, a reduction of Empire's allowed return on equity from 9.9 percent to 9.0 percent would be a move in the right direction, without increasing Empire's risk.

According to Dr. Vander Weide, Mr. Garrett tested the reasonableness of his recommendations by comparing the average awarded ROE for U.S. electric utilities from 2005 to 2016 to Dr. Damodaran's estimates of the market cost of equity over the same period. The average electric utility awarded ROE over the period 2005 to 2016 was approximately 200 basis points higher than Dr. Damodaran's average estimate of the market cost of equity. Because Mr. Garrett believes that Dr. Damodaran has provided a reasonable estimate of the required market return, Mr. Garrett concludes that: (1) utility commissions, such as the Oklahoma Corporation Commission, have consistently awarded allowed ROEs that exceed utilities' costs of equity by more than 200 basis points; and (2) the Commission should significantly reduce Empire's current 9.9 percent allowed ROE.

Dr. Vander Weide testified that Dr. Damodaran's data simply represents the results of a mechanical application of his market model to market data for the S&P 500. Mr. Garrett fails to acknowledge that public utility commissions generally set a utility's allowed ROE equal to the commission's best estimate of the utility's cost of equity based on the evidence presented in each proceeding. According to Dr. Vander Weide, Mr. Garrett provided no evidence that utility commissions intentionally set a utility's allowed return above the best estimate of the utility's cost of equity. To suggest otherwise is an insult to Commissioners, according to Dr. Vander Weide.

Dr. Vander Weide noted that one of Mr. Garrett's sources in his testimony is the Graham and Harvey annual survey of chief financial officers. In this survey, Graham and Harvey ask the CFO survey participants to provide information on: (1) their companies' internally calculated weighted average costs of capital; and (2) the hurdle rates their companies use to make investment decisions. Graham and Harvey find that the average internally calculated WACC for U.S. companies is in the range 9.3 percent to 9.7 percent, and that the average hurdle rate used to make investment decisions is in the range 13.1 percent to 14.2 percent.

Dr. Vander Weide explained that the "hurdle rate" is the "cut-off" return a company uses as the target rate of return that must be expected to be earned in order to make the investment in the project. For example, a company with a "hurdle rate" of 12 percent, will only accept projects with a return on total invested capital (debt plus equity) greater than 12 percent. He further stated that the company's weighted average cost of capital is the minimum return on total capital that would allow a company to break-even on a project; that is, the project would have a net present value equal to zero. Companies generally set the investment hurdle rate higher than the WACC, in a world of capital constraints, in order to earn a positive net present value on a project.

Dr. Vander Weide further explained the relevance of the Graham and Harvey finding. The data provides a better test of the reasonableness of Mr. Garrett's recommended 9.0 percent ROE and 7.14 percent WACC because they reflect the costs of capital managers actually use to make real-world investment decisions rather than a mechanical application of a formula to market data without any consideration of whether investors actually use this formula in making investment decisions. Thus, in summary, the WACCs and hurdle rates reported by Graham and

Harvey indicate that Mr. Garrett's recommended 9.0 percent allowed ROE and 7.14 percent WACC are far below a reasonable estimate of Empire's cost of equity and weighted average cost of capital. ["The Equity Risk Premium in 2016," John R. Graham and Campbell R. Harvey]

Dr. Vander Weide rebutted Mr. Garrett's 7.5 percent estimate of Empire's cost of equity.

According to Dr. Vander Weide, Mr. Garrett applied the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") to a group of eighteen Value Line electric utilities. Mr. Garrett also applied his cost of equity models to Dr. Vander Weide's larger proxy group, attempting to establish that "cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups." [Garrett at 23] Mr. Garrett's group excludes companies with market capitalizations "considerably higher than Empire's market capitalization."

Dr. Vander Weide testified that both Mr. Garrett and Dr. Vander Weide used the quarterly DCF model. Mr. Garrett obtained a result of 7.6 percent.

Dr. Vander Weide testified that using the analysts' growth forecasts in Mr. Garrett's DCF model produces a result equal to 9.5 percent, not the 7.6 percent reported by Mr. Garrett.

Dr. Vander Weide's quarterly DCF model results differ from Mr. Garrett's primarily because he used analysts' estimates of long-term growth for the growth component of the DCF model, whereas Mr. Garrett used his estimate of long-run growth in Gross Domestic Product ("GDP") for the growth component of his DCF model.

Dr. Vander Weide used analysts' growth rates reported by I/B/E/S Thomson Reuters because his studies indicate that the analysts' growth rates are highly correlated with stock prices. This evidence provides strong support for the conclusion that investors use analysts' growth rates in making stock buy and sell decisions, and thus the analysts' growth rates should be used to estimate the growth component of the DCF model.

Dr. Vander Weide discussed the analysts' estimates of future EPS growth by saying that part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts.

He further testified that I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as an estimate of future firm performance.

Dr. Vander Weide used the I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutions and other investors.

Dr. Vander Weide relies on analysts' projections of future EPS growth rather than historical growth, retention growth, or long-run growth in GDP because there is considerable empirical evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth. The evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth is important according to Dr. Vander Weide because the DCF model requires the growth expectations of investors.

Dr. Vander Weide testified that he had prepared a study in conjunction with Willard T. Carleton, Professor of Finance Emeritus at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in *The Journal of Portfolio Management*.

Dr. Vander Weide summarized the results of the study. First, a correlation analysis was performed to identify the historically oriented growth rates which best described a firm's stock price. Then a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates.

These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. It should be noted that researchers at State Street Financial Advisors updated Dr. Vander Weide's study, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Dr. Vander Weide testified that Mr. Garrett believes that it is inappropriate to use analysts' growth rate forecasts to estimate investors' growth expectations in the DCF model because analysts' growth forecasts generally exceed the projected long-term growth of the economy as a whole; and, in Mr. Garrett's opinion, it would be irrational for investors to believe that companies can grow forever at a rate in excess of the expected growth in the economy.

According to Dr. Vander Weide, Mr. Garrett also considers inflation, real GDP, and the current risk-free rate as additional estimates of long-term GDP growth. However, the 4.1 percent long-term growth estimate that Mr. Garrett uses in his DCF calculation is based entirely on an estimate of nominal GDP growth.

Dr. Vander Weide did not believe it was appropriate for Mr. Garrett to adjust the growth term in his DCF model, without also adjusting the stock price term in his model.

Dr. Vander Weide testified that Mr. Garrett failed to recognize that the DCF model requires the growth expectations of *investors*, not the growth expectations of Mr. Garrett. If investors use analysts' growth rates to value stocks in the marketplace, Mr. Garrett should use analysts' growth rates to estimate the growth component of the DCF model. Mr. Garrett also failed to recognize that companies do not have to grow at the same rate forever for the single-stage DCF Model to be a reasonable approximation of how prices are determined in capital markets.

Dr. Vander Weide further testified that Mr. Garrett's opinion that a company's earnings cannot grow at a rate greater than the rate of growth in the GDP forever does not imply that companies must grow at an expected GDP growth rate in every year. Mr. Garrett's assumption that companies must only grow at the same rate as his estimate of expected GDP growth is completely arbitrary. Further, Mr. Garrett did not examine more than one estimate of nominal long-term GDP growth according to Dr. Vander Weide.

Dr. Vander Weide further testified that he did not believe that long-term GDP growth is the growth estimate investors use when they invest in stocks and, therefore, is not appropriately used as the estimate of growth in the DCF model. He was aware that estimates of nominal long-term GDP growth are available from the Social Security Administration and the Energy Information Administration, for example; and the current nominal long-term GDP estimates from these sources are 4.6 percent and 4.3 percent, approximately 50 basis points and 20 basis points higher than the 4.1 percent estimate used by Mr. Garrett.

Dr. Vander Weide did not agree with Mr. Garrett's CAPM result. Mr. Garrett's estimate of the risk-free rate, his estimate of the risk premium on the market portfolio, and his failure to acknowledge the substantial evidence that the CAPM tends to underestimate the cost of equity for companies such as his proxy companies with betas less than 1.0 were all points of disagreement.

Dr. Vander Weide disagreed with Mr. Garrett's 3.04 percent estimate of the risk-free rate because the analysis presented in his direct testimony indicates that the forecasted yield on long-term Treasury bonds is approximately 4.1 percent. In estimating the forward-looking equity risk premium on equity investments, it is reasonable to use a forecasted interest rate rather than a current interest rate on long-term Treasury securities.

Given the convincing evidence that the CAPM underestimates the cost of equity for companies with betas less than 1.0, Mr. Garrett should have recognized, for this reason alone, that his cost of equity estimates underestimates Empire's cost of equity.

Dr. Vander Weide further testified that Graham and Harvey state that executives report that their firms use actual weighted average costs of capital in the range 9.3 percent to 9.7 percent, and they report that they use investment hurdle rates in the range 13.1 percent to 14.2 percent. Graham and Harvey's reported information on the WACCs and hurdle rates actually used by executives to make investment decisions is more relevant to assessing Empire's cost of equity than the information on executives' views on expected returns.

Because both the weighted average cost of capital and the hurdle rate are weighted averages of the cost of debt and the cost of equity, and the cost of debt is less than the cost of equity, the costs of equity that executives actually use in making real world investment decisions must be significantly higher than the weighted average cost of capital or hurdle rate. Thus, based on this evidence, the market risk premium must be considerably higher than Mr. Garrett's assumed 5.8 percent, and the cost of equity must be considerably higher than Mr. Garrett's calculated 7.4 percent CAPM cost of equity using a 5.8 percent market risk premium.

Dr. Vander Weide also had several concerns with Mr. Garrett's study of the implied market return on the S&P 500. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

With regard to the risk-free rate component of the CAPM, Dr. Vander Weide recommends using a forecasted yield to maturity on Treasury bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Because current interest rates are depressed as a result of the Federal Reserve's efforts to stimulate the economy by keeping interest rates low, current interest rates at this time are a poor indicator of expected future interest rates. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

Dr. Vander Weide concluded that Mr. Garrett's CAPM cost of equity estimate is unreasonably low and significantly less than Empire's true cost of equity.

Dr. Vander Weide also rebutted Mr. Garrett's views regarding: (1) the risk of investing in regulated utilities such as Empire; (2) the appropriate upper bound estimate of Empire's cost of equity; and (3) the relationship between depreciation and the cost of capital.

Dr. Vander Weide discussed the risks of investing in regulated electric utilities in his direct testimony on pages 13 – 19. In his discussion, he noted that the business risks of investing in electric utilities is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Mr. Garrett argues that Dr. Vander Weide's analysis of the business risks of investing in regulated utilities is misleading because the risks he identifies are all "firm-specific risks" that have no "meaningful effect on the cost of equity estimate," and his view that the regulatory process creates additional risks for utilities is completely untrue. Garrett believes that regulation significantly reduces the risk of investing in electric utilities, rather than increasing the risk of investing in electric utilities.

Dr. Vander Weide testified that the business risks he identified cannot be diversified away because they reflect general risks faced by investors in all industries, rather than the specific risks faced only by investors in electric utilities. He discusses these risks in the context of the electric utility industry to emphasize that the risks of investing in electric utilities has increased as a result of the high costs of meeting increasingly stringent environmental regulations, the impact of technological change has on reducing the demand for electricity generated and sold by electric utilities, and the challenge and complexity of identifying appropriate responses to changing economic conditions in the industry. The structure of the electric utility industry is changing dramatically as more customers are able to obtain electricity from sources other than traditional utilities.

Dr. Vander Weide testified that Mr. Garrett estimated that the average market cost of equity is 8.1 percent.

Mr. Garrett arrives at his 8.1 percent estimate of the market cost of equity by examining the results of the IESE survey, the Graham and Harvey survey, Damodaran, and his own study.

Mr. Garrett concludes that the upper bound for a reasonable estimate of Empire's cost of equity is 8.1 percent.

Dr. Vander Weide testified that Mr. Garrett's conclusion is based on sources that do not provide studies of the cost of equity either for utilities or for the market. Market surveys of executive opinions regarding the expected risk premium on the S&P 500, such as the IESE survey and the Graham and Harvey survey, are not designed to establish an appropriate upper bound for the cost of equity for electric utilities. The Graham and Harvey survey, for example, provides evidence that the executives responding to the survey, in fact, do not use the risk premium data they provide in response to the survey when they are committing their companies' funds to capital projects. Rather, the Graham and Harvey survey provides evidence that companies' use hurdle rates in the range 13.1 percent to 14.2 percent. This 13.1 percent to 14.2 percent range includes both debt and equity costs. Mr. Garrett's 8.1 percent estimate of an upper bound for an electric utility's cost of equity is far below the costs equity that are used to establish hurdle rates for real-world investment decisions.

Mr. Garrett's study on the implied market return on the S&P 500 is flawed in several ways. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

Dr. Vander Weide testified that Mr. Garrett claimed that it was best to over-estimate depreciation lives in depreciation studies because such over-estimation does not harm the company and benefits shareholders. Mr. Garrett stated:

> Moreover, since the Company's awarded and earned returns on equity are far above its true cost of equity, the Company's shareholders further benefit from the excess wealth transfer from ratepayers while these costs are in rate base. Thus, the process of depreciation strives for a perfect match between actual and estimated useful life. When these estimates are not exact, however, it is better that useful lives are overestimated rather than underestimated. [Garrett Depreciation Testimony at 7 – 8]

According to Dr. Vander Weide, Mr. Garrett's assertion is based on his faulty conclusion that Empire's cost of equity is 7.5 percent. Dr. Vander Weide noted that he had been involved in regulatory proceedings for many years, and he could not recall any regulatory commission awarding an allowed rate of return on equity as low as Mr. Garrett's recommended 7.5 percent cost of equity. He had not experienced, and did not believe, Mr. Garrett's assertion that regulators have awarded allowed returns on equity above utilities' cost of equity.

Dr. Vander Weide further testified that Mr. Garrett's statement that utilities "routinely propose awarded returns on equity that far exceed their actual costs of equity for the sole benefit of shareholders, as Empire has done in this case" [Garrett Depreciation Testimony at 34 – 35] is specious, self-serving, and contrary to the extensive evidence presented by the Company in this proceeding. Dr. Vander Weide provided evidence in this case on Empire's cost of equity, and Empire has proposed an allowed return on equity that is equal to his cost of equity estimate, which is based on the average result of his application of the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities. Dr. Vander Weide's estimate of Empire's cost of equity is not only equal to Empire's current allowed ROE in Oklahoma, but is also in line with allowed rates of return for electric utilities throughout the country. To the contrary, Mr. Garrett's 7.5 percent estimate of the cost of equity is far lower than any allowed rates of return on equity.

Dr. Vander Weide did not agree with Mr. Garrett's claim that a company's shareholders benefit if depreciable lives are over-estimated. If depreciable lives are over-estimated, shareholders face the considerable risk that they will not recover the full cost of their investment in these assets.

Mr. Rush accepts Empire's requested 9.9 percent ROE, Dr. Vander Weide did not rebut his recommendation to award Empire an allowed ROE equal to 9.9 percent.

Dr. Vander Weide did not agree with the method that Mr. Rush arrived at his 7.91 percent cost of equity estimate.

Mr. Rush arrives at his 7.91 percent cost of equity estimate by applying the DCF, CAPM, and comparable earnings methods to a proxy group of 29 Value Line electric utilities.

Dr. Vander Weide disagreed with Mr. Rush's decisions to: (1) use quarterly dividends from the second quarter of 2016 along with stock prices for the period December 23, 2016, through February 7, 2017; and (2) use of historical dividend growth and fundamental growth along with Value Line's projected earnings growth to estimate the growth component of the DCF model.

Dr. Vander Weide disagreed with Mr. Rush's use of quarterly dividends from the second quarter of 2016 with stock prices from December 23, 2016, through February 7, 2017, inputs because the DCF model is based on the assumption that investors value a stock based on their estimate of the present value of all expected <u>future</u> dividends. Mr. Rush's decision to use dividends from the second quarter 2016 with stock prices from December 23, 2016, through February 7, 2017, violates this basic assumption because Mr. Rush's dividends were paid prior to the observed stock prices. Thus, Mr. Rush's DCF analysis includes a fundamental mismatch of data.

According to Dr. Vander Weide, Mr. Rush estimates the growth component of his DCF analysis from information on his proxy companies': (1) historical dividend growth over the last five years as reported by Value; (2) projected earnings per share growth as reported by Value Line; and (3) fundamental growth. Mr. Rush's final growth estimate is the average of these three growth estimates. Mr. Rush's data for these growth inputs are shown in Exhibit DG-C-6 in his Excel work papers.

The DCF model requires the growth forecasts investors use to value stocks in the marketplace; and Dr. Vander Weide's studies indicate that investors use consensus analysts' earnings per share growth ("EPS") forecasts to value stocks in the marketplace. Mr. Rush should have relied on analysts' earnings per share growth forecasts rather than on historical dividend growth and fundamental growth forecasts.

Dr. Vander Weide further testified that there appeared to be errors in Mr. Rush's growth data. Mr. Rush's work papers indicate that rather than using the Value Line reported historical dividend growth rates for his proxy companies, the formula on his spreadsheet substitutes a zero percent historical growth rate for 18 out of his 29 proxy companies. Mr. Rush reports an average historical growth rate equal to 2.16 percent, whereas the historical average dividend growth rate is 4.93 percent once his formula and data are corrected.

If Mr. Rush had correctly matched dividend and stock price inputs and used the I/B/E/S growth forecasts, he would have obtained a DCF result equal to 9.1 percent. Using the Value Line projected earnings growth forecast as the growth term in his DCF model, Mr. Rush would have obtained a DCF result equal to 9.0 percent.

Dr. Vander Weide testified that because of an error in the formula in his spreadsheet, Mr. Rush reports an annual DCF model result equal to 4.49 percent. However, once errors in the formula that produces this result are corrected, along with the corrections in the growth rates and dividend inputs in the analysis, the annual DCF model result is 9.0 percent.

Regarding the CAPM analysis of Mr. Rush, Dr. Vander Weide testified that for his estimate of the risk-free rate, Mr. Rush uses the 2.90 percent average yield on 30-year Treasury bonds over the period December 15, 2016, through January 30, 2017. For his estimate of the company-specific risk factor or beta, Mr. Rush uses the average 0.71 Value Line beta for his proxy companies. For his estimate of the expected risk premium on the market portfolio, Mr. Rush uses: (1) historical geometric and arithmetic mean risk premium data reported by Ibbotson; (2) the expected risk premiums reported in the Graham and Harvey and the IESE Business School surveys discussed above; and (3) an implied equity risk premium calculation, which is the same as that used by Mr. Garrett. Based on these data, Mr. Rush uses 5.5 percent as his estimate of the risk premium on the market portfolio.

According to Dr. Vander Weide, Mr. Rush should have used a forecasted yield on Treasury bonds because interest rates have been at unusually low levels, and investors are forecasting that interest rates will increase over the period when Empire's rates will be in effect.

Dr. Vander Weide did not agree with Mr. Rush's historical equity risk premium estimates. Mr. Rush used an average of both the geometric and arithmetic mean historical risk premium estimates. The arithmetic mean risk premium is the only risk premium that will make the initial investment grow to the expected value of the investment at the end of the period. For an investment, such as an equity investment in stocks, which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future.

Dr. Vander Weide also disagreed with Mr. Rush's use of total return on long-term government bonds to estimate the difference between stock and bond returns because the CAPM requires an estimate of the risk-free rate, but the total return on long-term government bonds is not risk free because it includes capital gains and losses. A correct estimate of the historical risk premium is 6.9 percent, not the 5.2 percent reported by Mr. Rush.

In regards to Mr. Rush's comparable earnings method, Dr. Vander Weide stated that Mr. Rush calculates the average annual earned return on equity for each of his proxy utilities for the years 2012 through 2016. Mr. Rush reports that the average earned return for his group of proxy utilities over this historical period is 9.82 percent, and he uses 9.82 percent as his comparable earnings estimate of Empire's cost of equity.

Dr. Vander Weide had at least three criticisms of Mr. Rush's comparable earnings method. First, Mr. Rush should have used forecasted returns on equity rather than historical returns on equity to estimate each company's ROE. Mr. Rush himself acknowledges that historical returns on equity "should be considered with caution" because they do "not account for any prospective forward-looking factors." [Rush at 35] Further, the historical reported returns include factors such as one-time write-offs that are not expected to occur in the future. Second, Mr. Rush should have examined forecasted earned returns for comparable-risk industrial companies, as Mr. Rush himself also acknowledges [Rush at 34 – 35]. Third, Mr. Rush failed to recognize that Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, Mr. Rush should have adjusted Value Line's estimates to reflect rates of return on average equity for each year.

BLAKE A. MERTENS

<u>Direct Testimony</u>

Mr. Blake A. Mertens, Vice President Energy Supply and Delivery Operations for Empire, testified on behalf of Empire.

Mr. Mertens testified that the Asbury Power Plant is a 195 MW coal-fired power plant in northern Jasper County, Missouri, near the Missouri–Kansas state line. The Asbury Power Plant commenced commercial operations on July 1, 1970. The Babcock & Wilcox cyclone boiler was designed to be fueled by bituminous coal from the Pittsburg & Midway mine, which was adjacent to the Asbury Power Plant. Superheated steam from the boiler drove a Westinghouse turbine generator set to generate electrical energy.

According to Mr. Mertens, early pollution controls consisted of an electrostatic precipitator to capture particulate emissions. In the early 1990s, the Environmental Protection Agency created the Acid Rain Program, which required Empire to reduce sulfur dioxide emissions and led to a fuel switch from the local bituminous coal to lower sulfur sub-bituminous coal from the Powder River Basin of Wyoming. This required changes to the fuel handling system to accommodate the higher volume of this less energy dense coal and most notably, the construction of a rotary car dumper to unload the trainloads of coal. In 2008, in anticipation of nitrogen oxides emissions reductions to be required by the Clean Air Interstate Rule, Empire installed a selective catalytic reduction ("SCR") system at the Asbury Power Plant. The SCR injects anhydrous ammonia into the flue gas stream, where in the presence of a catalyst, it reacts with nitrogen oxides to eliminate them.

According to Mr. Mertens, the Federal Clean Air Act and state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control requirements. These requirements include maximum emission limits for sulfur dioxide ("SO2"), particulate matter, nitrogen oxides ("NOx"), carbon monoxide ("CO") and hazardous air pollutants, including mercury. To comply with current and pending environmental regulations, Empire needed to implement a compliance plan at its Asbury unit if the unit was to continue in service. The regulations primarily driving Empire's compliance plan are the Mercury and Air Toxics Standards ("MATS") and the Clean Air Interstate Rule ("CAIR") and its subsequent replacement rule.

Mr. Mertens testified that as part of its 2010 Integrated Resource Plan ("IRP") -- a twenty year planning study -- Empire developed seventeen different resource cases for analysis. Among the alternative resource cases analyzed, the study considered cases that included the construction of the Asbury AQCS or the retirement of Asbury in 2015. Capacity expansion modeling was done for all cases. New conventional and renewable resources, as well as demand-side management programs, were considered available for the capacity expansion required to meet Empire's projected future loads. The resources evaluated to replace or supplement the energy produced by Asbury included supercritical coal, simple cycle combustion turbine, combined cycle, nuclear power purchase agreement, distributed generation, integrated gasification combined cycle, wind, biomass and solar thermal.

Each of the seventeen cases analyzed in the 2010 IRP produced an optimized set of supply-side resources resulting in the lowest present value of revenue requirements ("PVRR") for the scenario represented by that case. Each plan was subjected to stochastic analysis and financial modeling over the planning horizon. Each plan was analyzed at all levels of four critical uncertain factors - environmental costs, market and fuel prices, load forecast and capital and transmission costs and interest rates. This analysis generated seventy-two endpoints for each plan, which make up the risk profiles for the plans.

The risk profiles of the cases that utilized the base case assumptions were compared, and the plan with the lowest risk with respect to PVRR was selected by Empire as its Preferred Plan. This Preferred Plan included the installation of the Asbury AQCS in the 2015 timeframe.

Mr. Mertens further testified that the economic analyses conducted before, during and after the preparation of the 2010 IRP, found that the Asbury AQCS project was the low-cost option for Empire. Additionally, this plan kept approximately 189 MW of Empire owned coal-fired capacity in Empire's generation mix, which helps with fuel diversity and fuel price volatility. With the continued operation of Asbury, Empire's owned generation mix is about 33% coal and 63% natural gas.

According to Mr. Mertens, in March 2010, Empire awarded Black & Veatch an engineering assignment to gather information about Empire's Asbury unit and perform studies to select the preferred technology for reducing emissions – specifically sulfur dioxide, particulate matter and mercury – at the plant. Black & Veatch prepared four individual reports as a result of this assignment:

- Balanced Draft Conversion Study, which examined the adequacy of the existing draft system, including the forced draft fans and recommended the boiler be converted from forced draft to balanced draft operation.

- Air Quality Control Technology Description Study, which identified spray dry absorber and circulating dry scrubber ("CDS") as flue gas desulfurization technologies that should be studied further.

- Study of the Two Alternative Suites of Air Emission Control Technology Equipment, the further study recommended by the Air Quality Control Technology Description Study, which identified CDS as the preferred technology for flue gas desulfurization at the Asbury unit.

- Chimney Analysis, which examined the adequacy of the existing chimney at the Asbury unit and recommended the construction of a new chimney as part of the project.

These four reports – along with site arrangement drawings, process flow diagrams, cost estimates and schedules – comprise the Asbury Environmental Retrofit Project Definition.

The cost estimates in the Asbury Environmental Retrofit Project Definition were incorporated with the estimate Empire used in the 2010 IRP, and used in affirming the decision to move forward with developing and issuing a request for proposals in mid-2011. Five Asbury AQCS construction proposals were received in September 2011, and all but one of the proposals compared favorably to previous estimates of the project cost, further affirming the decision to move forward with the project.

Mr. Mertens testified that a matrix was developed for the preliminary evaluation of the proposals. The proposals were evaluated on the following criteria: cost, including construction and operation and maintenance costs; schedule; performance guarantees; commercial terms and conditions; contractor safety record and project experience. Sega, Empire's owner's engineer for the project, aided in the technical evaluation of the proposals without sharing in any pricing or other commercial information. Following preliminary evaluations of the proposals, two bidders were selected to come to Empire's offices to present their experience and their plan to successfully complete the Asbury Environmental Retrofit. Empire's project team recommended to Empire's Board of Directors Strategic Project Committee that a budget be approved to allow for contract negotiations and the completion of the Asbury AQCS. The Board of Directors approved a resolution based on the project team's recommendation at its regular meeting in October 2011.

Mr. Mertens described the construction of the AQCS. He stated that work on the site began in February 2012, with actual construction activities getting underway in May of that year. Foundations and underground utilities were the first activities to be completed. Construction of the new chimney was also scheduled early in the sequence due to the large personnel exclusion zone that comes with overhead work. Structural steel deliveries and erection began in early 2013 and were completed in late 2013. Construction of the scrubber and baghouse began in May 2013 and finished in the second quarter of that year. Commissioning of Asbury AQCS systems began in January 2014, and the Asbury unit came offline for tie-in of the AQCS on September 11,

2014. Asbury returned to service on November 5, 2014, and initial scrubber tuning began on November 8, 2014. In-service testing began on December 7, 2014, and was completed on December 13th. Empire declared the Asbury AQCS in-service on December 15, 2014, upon validation of the test results. All performance testing was completed on February 5, 2015.

Mr. Mertens testified that the Riverton 12 NGCC project involved converting the existing Riverton Unit 12 simple cycle gas turbine, which went into service in 2007, to a combined cycle gas turbine. The conversion included the installation of a heat recovery steam generator, steam turbine generator, auxiliary boiler, cooling tower, and other balance of plant equipment. The Riverton 12 NGCC will be the most efficient generator in Empire's fleet and was identified in Empire's 2013 IRP, filed with the Missouri Public Service Commission ("MPSC") in Docket No. EO-2013-0547, as a least cost option to comply with environmental regulations including the Cross State Air Pollution Rule ("CSAPR").

According to Mr. Mertens, the Missouri Electric Utility Resource Planning rules "require the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy." (Missouri Code of State Regulations 4 C.S.R. 240-22.070). In addition, among other conditions, "in the judgment of the utility decision-makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short-term and emergency power supplies, [must have] sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4 CSR 240-22.030(8)(B) for the implementation period." Also, among the fundamental objectives of the resource planning process included in the Missouri IRP rules is that a utility shall "[u]se minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan, subject to the constraints in" 4 CSR 240-22.010(1)(C).

The preferred plan, which included the Riverton 12 NGCC conversion project, was selected among 18 alternative resource plans developed by Empire in MPSC Docket EO-2013-0547.

According to Mr. Mertens, the parties to the MPSC Docket EO-2013-0547 came to an agreement concerning Empire's 2013 IRP filing on January 31, 2014.

Mr. Mertens further testified that Black and Veatch, an engineering firm based in Kansas City, Kansas, was contracted by Empire to serve as Owners Engineer in the development of the RFP for the Riverton 12 NGCC Engineer, Procure, Construct ("EPC") Contract. The EPC Contract RFP included Commercial and Technical Sections for the construction of Riverton 12 NGCC. Also included in the EPC contract were Commissioning activities. Work began on the RFP specifications in September 2012 and was completed in December 2012. The RFP was sent out on January 3, 2013, to six different firms: Burns & McDonnell, SEGA Engineering, Kiewit Construction, Enerfab, Alberici Constructors, Sargent & Lundy, and Fluor. Bids were due on April 9, 2013. A Pre-bid meeting was held on January 16, 2013, at the Riverton site.

The EPC contract did not include Empire labor & overheads, professional services, permitting, fuel costs net of market revenue, and site preparation.

Mr. Mertens testified that the proposals were received from four bidders: Burns & McDonnell, Enerfab, Sega, and Riverton Partners – a joint venture of Alberici Constructors and Sargent & Lundy. Proposals were reviewed for technical acceptability and completeness by the

Empire Team and Black & Veatch. Commercial Terms and Conditions were reviewed by the Empire Team. A matrix was developed for the preliminary evaluation of the proposals. The proposals were evaluated on the following criteria: cost, schedule; performance guarantees; commercial terms and conditions; contractor safety record and project experience. Black & Veatch, Empire's owner's engineer for the project, aided in the technical evaluation of the proposals without sharing in any pricing or other commercial information. Burns & McDonnell was ultimately selected as the preferred EPC contractor and the EPC contract was agreed to by both parties on July 9, 2013.

Burns & McDonnell performed all Engineering, Procurement, and Construction aspects of Riverton 12 NGCC. All engineering documents including design, layout, construction, and equipment supplier information was reviewed by the Empire Riverton 12 Project Team and Black & Veatch for technical acceptability. Any questions regarding such documents were submitted to Burns & McDonnell for clarification. Weekly telephone conference calls were held between Burns & McDonnell, the Empire Riverton 12 Project Team and Black & Veatch throughout the project. In addition, monthly progress meetings were held either at Burns and McDonnell in Kansas City or at the Riverton 12 site. Burns & McDonnell provided construction management services while subcontracting major aspects of the project. Daily on-site construction meetings were held each morning with on-site contractors to discuss daily activities and issues. Weekly construction and schedule meetings were held with each on-site contractor separately to discuss construction progress and schedule. The Empire team attended all daily and weekly on-site meetings. An important aspect of all of these meetings was safety. The Empire team was in the field directly observing and witnessing construction and commissioning activities. Where appropriate, the Empire team was direct participants in the construction and commissioning process. Weekly construction progress meetings were held by the entire Empire Riverton 12 Project Team.

According to Mr. Mertens, Burns & McDonnell submitted monthly reports describing engineering, procurement, and construction efforts. Included in this report were engineering and construction progress reports discussing completed activities and upcoming activities. Construction issues were also discussed as well as schedule impacts. The Empire Riverton 12 Project Team also generated a monthly report discussing construction progress, project financial information, and any project issues.

The Riverton 12 NGCC unit went into service on May 1, 2016.

<u>Rebuttal Testimony</u>

Mr. Mertens' rebuttal testimony addressed the purported reliability issues raised by Mark E. Garrett and Edwin C. Farrar in their direct testimonies with regards to service provided to Empire's Oklahoma customers. He also addressed Mr. Garrett's claims that sufficient evidence has not been provided regarding plant additions.

According to Mr. Mertens, in 2010, Empire developed a 10-year plan to construct system improvements solely to improve the reliability of the system. This reliability plan is often referred to as Operation Toughen-Up. Empire is still in the midst of implementing this plan which is slated for completion in 2021. The Oklahoma projects included in Operation Toughen-Up were discussed by Mr. Mertens and Exhibit BAM-1 illustrated the geographic area impacted by these projects.

Mr. Mertens testified regarding the following projects:

Distribution automation for Welch (Completed 2013) – This project created a backup distribution source to support the Welch load in the event that their primary radial source was no longer energized. This is an automated process that changes the configuration of the distribution system such that the Welch load will be served from the Fairland Substation. With this system, the Welch load is restored in less than 3 minutes after the initial power outage. The cost of this project was $700,010.

Welch transmission line rebuild (Completed in 2016) – The transmission system that supplied the Welch substation was in poor condition due to its age. Therefore, the entire 27 miles of Radial transmission line was rebuilt with all new components and conductor. In an effort to improve the reliability of this transmission line, the phase spacing was increased to prevent flashovers, the conductor was significantly increased in size to improve resistance to physical damage, and all of the wood poles were replaced with steel to resist damage from wood peckers and decay. The cost of this project was $11,322,194.

Welch transmission voltage upgrade (Scheduled for 2018) – This project will be to convert the transmission system serving the Welch substation from the existing 34.5 kV to 69 kV. This will reduce the specialized equipment needed to maintain and operate the 34.5 kV system. Currently, Empire utilizes predominantly 69 kV or higher systems on its transmission system. Therefore, spare equipment is more readily available for repairs at the 69 kV voltage. This project is estimated as $3,959,000.

Fairland installation of 2 - 69 kV breakers and increase substation transformer size (Completed in 2015) – This project removed the exposure of 15.5 miles of transmission line from the customers served by the Fairland West, the Fairland Southwest and the Fairland Shell substations. Prior to this system upgrade, any incident that caused an outage on the transmission line also caused the customers served by any of these substations to experience an outage. The cost of this project was $1,474,426

Installation of 69 kV throw-over switching scheme at Commerce Tap (Scheduled in 2018) – This project is to install a throw-over switch in the transmission line that serves Commerce so that automatic sectionalization can occur to restore service to Commerce in the event of a transmission line event. This project is estimated to cost $500,000.

Fairland installation of additional 12 kV breaker and circuit conductor (Completed in 2016) – This project increased sectionalization of the distribution system and reduced the number of customer outages due to a single distribution event. The cost of this project was $140,029.

Reducing Distribution Outage Exposure (Ongoing) – To date, Empire has spent $223,215 to install sectionalizing devices (reclosers and fuses) to reduce the number of customers that experience an outage for each fault.

Mr. Mertens testified that Oklahoma customers make up less than three percent of Empire's customer base. However, since the inception of this reliability program, Empire has spent nearly 32% of its expenditures for the benefit of Oklahoma customers. At the completion of the program, Empire reasonably expects that approximately 14% of the expenditures will provide benefit to Oklahoma customers.

According to Mr. Mertens, Empire did not distinguish between the states with regards to its maintenance programs. In 2008, the Missouri Public Service Commission ("PSC") implemented reliability inspection standards that dictated the frequency and thoroughness of system inspections and repairs. Since the implementation of that rule, Empire has elected to implement the Missouri standards for inspections and repairs for facilities in all jurisdictions served by Empire. The Missouri rules for system inspections and repairs exceed any Oklahoma requirements for inspections and repairs. Additionally, Empire adheres to the Oklahoma vegetation management rules, which are more restrictive than those established for Missouri.

Mr. Mertens testified that Empire was in the midst of substantial system upgrades to improve the service to the customers in Oklahoma; however, the impact from these new systems take time to effect annual SAIDI and SAIFI indices, as not all of the projects are installed. Also, in order to install these systems economically, the system is put into a less reliable condition during the construction of the new upgrades. Naturally this results in SAIDI and SAIFI indices that are much worse than what will be expected at the conclusion of the overall program.

According to Mr. Mertens, Empire monitors the reliability during construction of these reliability projects to make adjustments to construction methodologies to reduce the exposure to outages.

Mr. Mertens testified that in 2014 during the construction of the Welch transmission line, the method of construction caused significant reliability issues to the town of Welch. Due to the condition of the system at the time the reliability issues arose, there was no solution other than to expedite the construction with additional manpower. During the next phase of the construction of the transmission line, a different construction plan was developed to drastically limit the exposure of our customers to outages. During this phase of construction, the reliability for the town of Welch went from a SAIFI of 6.9 to 0.175.

Oklahoma reliability statistics have lagged compared to Empire's overall system reliability statistics. As reflected in BAM-Table 1 below, since the inception of the Operation Toughen-up program in 2011 our SAIDI and SAIFI statistics have continually improved due to system-wide improvements, as well as vegetation management program initiatives. As Empire completes the projects outlined above Empire reasonably expect Oklahoma's reliability metrics will follow suit.

BAM-TABLE 1: **System 2010 – 2016 SAIFI and SAIDI (Excluding Major Events)**

YEAR	SAIDI - EME	SAIFI - EME
2010	148.28	1.434
2011	239.69	1.696
2012	140.48	1.361
2013	146.53	1.345
2014	132.81	1.458
2015	114.77	1.357
2016	102.98	1.145

Mr. Mertens explained why the 2011 SAIFI and SAIDI statistics reflected in Table 1 were significantly higher relative to the other years. According to Mr. Mertens, in 2011 the city of Joplin was struck by a tornado inflicting substantial damage to the electrical system and causing an unusual number of outages.

In response to Mr. Garrett's reference to a 2016 JD Powers Customer Satisfaction Rating, Mr. Mertens testified that Empire did not subscribe to JD Power's service and is unaware of an official document in which a comprehensive customer satisfaction service was performed. Mr. Garrett's testimony did not include the reference for this document, nor did he identify the actual rating that Empire received or the JD Powers average rating. Empire is aware that JD Powers performs sample surveys in an effort to sell their services; however, Empire is not aware that a sample survey was performed.

EMPIRE DID NOT AGREE WITH MR. GARRETT'S STATEMENT ON PAGE 7 OF HIS RESPONSIVE TESTIMONY BEGINNING ON LINE 1 "SINCE ITS LAST RATE CASE IN 2011, EMPIRE HAS BEEN INVESTING LARGE AMOUNTS IN NEW RATE BASE WITH NO NOTICE TO THE COMMISSION OR TO THE COMPANY'S CUSTOMERS. IN HIS OPINION, IT IS IRRESPONSIBLE FOR A UTILITY TO SIT QUIETLY FOR FIVE YEARS BEFORE IT INFORMS ITS CUSTOMERS THAT IT INTENDS TO NEARLY DOUBLE THEIR BASE RATES."

The Company has engaged in significant customer communications, both direct and through the media, concerning the environmental compliance efforts and the potential impact on electric rates. The Company notified the Commission in its 2013 triennial Integrated Resource Plan ("IRP") reports of its planned generation investments. Furthermore, the Company again notified the Commission that it was making significant investments in its generation fleet and that rather than file two rate cases, one in 2015 and another in the third quarter of 2016, it would be more cost effective to file one case for the approximate 4,700 Oklahoma customers.

Additionally, the Company notes that PUD was aware of the investments and the subsequent rate increases to recover such investments. Please refer to the Testimony of Geoffrey M. Rush who testified in December 2014 that the Company completed improvements to its Asbury Plant and was in the process of converting the Riverton 12 Plant into a combined cycle unit. The estimated completion date of Riverton 12 Plant was mid-2016. It was Mr. Rush's opinion that back-to-back rate cases would not only be burdensome to Empire but would not serve the public interest.

Finally, the Company would point out that in response to data request AG-EDE-2.16, for each electric plant addition project costing more than $1 million, since the last rate case and continuing through to six months after the end of the test year, Empire provided requested information related to its investments in generation, transmission and systems software which were included as BAM-Attachment 1.

BETHANY Q. KING

Bethany Q. King, employed by Empire as the Manager of Strategic Planning, testified on behalf of Empire.

Ms. King's testimony provided explanation of the customer growth, weather, and unbilled revenue adjustments made to Empire's income statement.

According to Ms. King, Oklahoma jurisdictional revenues have been adjusted to reflect the amount of revenue that would have been generated if the number of Empire customers existing at June 30, 2016, had been served by the Company for the entire test year. For the residential and commercial classes, the differences between the June 30, 2016, level of customers and the average customers billed in each month of the test year were multiplied by the average weather normalized kWh per customer for that month. The resulting change in kWh sales was then multiplied by the average class weather normalized cost per kWh to obtain the revenue adjustment related to customer growth.

In total, the customer growth adjustment to revenue resulted in an increase of $7,148 in revenue and 48,007 kWh in sales.

Ms. King further testified that the test year sales and revenue were adjusted to account for the impact of abnormal weather. The adjustment resulted in an increase to Oklahoma jurisdictional rate revenue of $173,250.

According to Ms. King, the revenue in the test year should equal the amount actually billed to customers and the portion of sales that were used but not billed during the test year. While the amount of revenues actually billed to customers is known, the portion not yet billed to customers is not known, and therefore, must be estimated. This adjustment is calculated by multiplying a rate per kWh to the unbilled sales by pricing plan. The unbilled sales computation is calendar normalized sales minus revenue cycle normalized sales. The unbilled sales were multiplied by the determined rates to derive the unbilled revenue. This resulted in an increase to revenue of $3,314.

DAVID SWAIN

Mr. David Swain, President of Empire, adopted the testimony of Brad P. Beecher.

Mr. Swain testified that Empire is a Kansas corporation with its principal office and place of business in Joplin, Missouri. Empire provides electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma.

According to Mr. Swain, Empire provides electric service in an area of approximately 10,000 square miles in southwest Missouri and the adjacent corners of the states of Kansas, Oklahoma, and Arkansas. Empire's operations are regulated by the utility regulatory commissions of these four states, as well as by the Federal Energy Regulatory Commission ("FERC"). Empire's service area embraces 119 incorporated communities in 21 counties in the four-state area. Most of the communities in Empire's service area are small, with only 32 containing a population in excess of 1,500. Only 10 communities have a population in excess of 5,000, and the largest city, Joplin, Missouri, has a population of approximately 50,000. The economy in Empire's service area is diversified. The service territory features small to medium manufacturing operations, medical, agricultural, entertainment, tourism, and retail interests.

Mr. Swain testified that since the Company's last rate increase, which became effective on January 6, 2012, Empire has continued to construct facilities necessary for the provision of service to its customers, including those located in Oklahoma. Total capital expenditures in this period were about $670 million. This includes the addition of Empire's Asbury Air Quality Control System environmental retrofit project ("AQCS"), the Riverton 12 Natural Gas Combined Cycle conversion project ("Riverton 12"), as well as significant additions to the Company's transmission and distribution systems.

In recent years, according to Mr. Swain, the EPA has tightened air quality standards for SOx, NOx, and Hg. These new standards affected the operations of several of Empire's power plants. Empire's Asbury and Riverton power plants were most affected by these revised standards. Environmental retrofits were already completed on Iatan 1, and the Plum Point and Iatan 2 facilities were constructed to meet the new standards. In response to the EPA's revised standards, Empire implemented a compliance plan. Empire's compliance plan called for the installation of a scrubber, fabric filter, and powder activated carbon injection system at the Asbury plant (collectively referred to as the "Asbury air-quality control system" or "AQCS") by early 2015. The addition of this air quality control equipment also required the retirement of Asbury Unit 2, a small steam turbine that was used for peaking purposes. The retirement of this unit took place in December of 2013, and the environmental project at Asbury was in service on December 31, 2014. Empire also invested in the conversion of its Riverton 12 generating unit to a combined cycle, which is the final component of Empire's compliance plan to meet EPA rules on air quality regarding SOx, NOx, and mercury ("Hg"). Empire's compliance plan also originally called for the eventual retirement of Riverton Units 7, 8, and 9 in 2016, though retirement of the units actually occurred slightly ahead of schedule. Unit 9 was a small combustion turbine that required steam from Unit 7 for start-up. Units 7 and 8 began operation in 1950 and 1954, respectively.

According to Mr. Swain, Empire representatives have attended various community forums and discussed the environmental compliance plan and how that plan may ultimately result in increased electrical rates for customers. In addition to these public presentations at various community forums, Empire has held meetings with community leaders and with the larger customers to discuss the environmental compliance activities and the estimated impact these activities will have on electric rates. Empire has also contacted the communications media to discuss the environmental compliance plan and its estimated impact on electric rates.

Mr. Swain further testified that the amount of the rate increase Empire is requesting is not related to the pending merger with Liberty, and all merger related costs have been excluded from Empire's request.

The transaction will have no adverse effect on Empire's customers. Empire has a dedicated and skilled workforce of managers, administrators and professional and field staff with expertise in regulated utility operations that has a strong reputation for delivering excellent customer service. The current work force will be retained as the transaction will not result in any involuntary reductions in Empire's current administrative, professional, and field workforce.

JEFFREY P. LEE, SR.

Jeffery P. Lee, Sr. Manager of Accounting & Administration for Empire, testified on behalf of Empire.

Mr. Lee testified that at this time, Empire is requesting total annual Oklahoma pension expense of $289,356, which represents an increase of $78,505 to the amounts authorized in rates pursuant to Cause No. PUD 201100082. This total includes actuarially determined expense of $240,660 and five-year tracker amortization of $48,696 for the pension plan.

Mr. Lee further testified that Empire is requesting total annual Oklahoma OPEB expense of $44,451, which represents a decrease of $32,441 to the amounts currently authorized. This total includes actuarially determined expense of $50,136 and a negative five-year tracker amortization of ($5,685).

These expenses for both Pension ("FAS 87") and OPEB ("FAS 106") costs for 2016 are final, according to Mr. Lee.

The 2016 actuarial valuation of the plans, which provides the cost, were completed in September of 2016.

MARK QUAN

Mr. Mark Quan, Principal Consultant in Itron's Forecasting Solutions group, testified on behalf of Empire.

Mr. Quan testified that he developed weather-normalized sales estimates for Empire. Using a statistical-based modeling approach, he developed weather-normalized sales for the historical test year. The test year is from July 1, 2015, through June 30, 2016. Mr. Quan stated that weather-normalized sales are estimated for the following five classes: Residential, Commercial, General Power, and Total Electric Building.

According to Mr. Quan, weather Normalization is the process of determining what historical consumption would have been if normal weather conditions existed. The process is a mathematical method which adjusts actual monthly sales for a class based on a statistical model and normal weather conditions.

AARON J. DOLL

Aaron J. Doll, the Associate Director of Supply Management for Empire, testified on behalf of Empire.

Mr. Doll testified that Empire first received approval of the Southwest Power Pool ("SPP") Transmission Tariff ("SPPTC") in the Final Order Approving Joint Stipulation and Settlement Agreement (Order No. 592623) in Cause PUD 201100082 on December 7, 2011. Original Tariff Sheet No. 24 ("Schedule SPPTC") became effective January 6, 2012. One of the components of the original SPPTC tariff was the requirement to file a base rate case within 42 months of the tariff's effective date (on or before July 5, 2015). In January 2015, Empire witness Bryan Owens filed Direct Testimony with the Commission proposing an amendment to the SPPTC tariff to remove the requirement to file a base rate case on or before July 5, 2015. The basis for this amendment was in regards to the timing of two separate investments in Empire's generation fleet. The first being the Asbury air quality control system ("AQCS") upgrade with an in-service completion date in late 2014 and the second being the Riverton 12 Combined Cycle conversion project with an expected in-service completion date in 2016. Empire's testimony stated that to "avoid rate case fatigue and significant costs associated with litigating back-to-back base rate cases", the proposed amendment would push back a general rate case until after the Riverton 12 project was in-service and therefore remove the July 5, 2015, base rate case requirement and authorize the continuation of the SPPTC tariff. On March 26, 2015, the Commission issued the Final Order in Cause PUD 201500012 stating that the amended SPPTC tariff would be granted but that in Empire's next general rate case a series of findings shall be presented in testimony.

Mr. Doll further testified that the findings require Empire to: 1) identify 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 for the previous years; 2) demonstrate that the amounts recovered under the SPP tracker were eligible for recovery, properly calculated, and appropriately allocated to rate classes; and 3) demonstrate that the costs of such upgrades were included in FERC-approved rates and allocated under an SPP cost allocation methodology and incurred by Empire during the previous years.

According to Mr. Doll, due to the voluminous nature of the documentation required to identify each of the third party upgrades and facilities that were constructed and included in the third party owned transmission costs, he included a link to the Revenue Requirement and Rates ("RRR") spreadsheets prepared by SPP for the timeframe beginning January 1, 2012. The RRR spreadsheet provides project specific details regarding revenue requirements and rates as they relate to both SPP zonal and regional Schedule 11 investment (tab labeled "Base Plan Rev. Req. Alloc"). Although SPP issues a new RRR spreadsheet as a result of a change to an input or formula rate update, the link included the most current January updates for years 2012 through 2016, as well as the most recent updated RRR at the time of filing (October 2016), which includes all of the projects and upgrades needed to satisfy the first requirement.

Mr. Doll testified the amounts recovered under the SPP tracker were eligible for recovery and were both calculated and allocated properly to the rate classes.

Mr. Doll testified that all of the rates that Empire has paid with respect to Schedule 11 were pursuant to the SPP Open Access Transmission Tariff ("OATT") which is a lawful tariff as determined by FERC. Regarding the SPP cost allocation methodology, the RRR spreadsheets provide details for the transmission investments including the cost allocation methodology (postage stamp-MW Mile methodology and highway/byway methodology). These cost allocation methodologies were detailed in the FERC approved SPP OATT.

Mr. Doll testified that Empire fulfilled all of the requirements listed in the final order in Cause PUD 201500012.

According to Mr. Doll, there were benefits of Empire's SPP membership. According to Mr. Doll, the SPP is a non-profit FERC approved Regional Transmission Organization ("RTO") operating out of Little Rock, Arkansas. The SPP provides services on behalf of its members including reliability coordination, tariff administration, regional scheduling, transmission investment planning, market operations, compliance and training. SPP began in 1941 and has evolved from a reliability council in the late 1960's, to an RTO in 2004, a Regional Entity in 2007, and administrators of the Energy Imbalance System ("EIS") also in 2007. The most recent evolution of the SPP has been the coordination of next day generation across the region through the creation of the SPP Integrated Marketplace ("IM") which commenced on March 1, 2014.

Mr. Doll testified that based on internal analysis simulating a bilateral market and utilizing production cost modeling with updated market prices, Empire estimates that the benefits of the SPP IM have resulted in $19.2 million or about 5% in total company fuel and purchased power savings from March 2014 through Third Quarter 2016.

ROBERT W. SAGER

Mr. Rob Sager, the Vice President of Finance and Administration for Empire, testified on behalf of Empire.

According to Mr. Sager, Ms. Champion has testified that the PUD's recommended revenue increase would result in significant impacts to customers if implemented at one time. As a result, PUD proposes that the increase be implemented over four (4) years to allow customers to better prepare for, and adjust to, the increase. Ms. Champion's proposal provides approximately 30% of the requested increase in year one (1), an additional 20% in year two (2), an additional 25% in year three (3), and the final 25% in year four (4), at which point the full amount of the recommended revenue increase would be recovered in rates.

Mr. Sager testified that PUD's proposed mitigation plan was not an adequate means of controlling the impact of the rate increase. Ms. Champion, as well as other witnesses, testified that Empire's last rate case was Cause No. PUD 201100082, which was based on 2010 costs, and that during this time Empire made significant capital investments. By not seeking recovery sooner, Empire incurred significant regulatory lag and forfeited the ability to earn on these investments earlier. While good intentioned, PUD's proposal exacerbates this rate lag by not allowing the full revenue requirement into rates until four (4) years into the future and fails to take into account the time value of money. PUD witness Mr. Robert Thompson recommends a rate increase of approximately $3.04 million. Ms. Champion acknowledges that recommendation, and proposes an approach that effectively reduces the total revenue that should be recovered over the proposed four (4) year period.

Mr. Sager testified that Empire would address the inadequacies in two ways. First, the Company suggested that the plan be reduced from four (4) years to three (3) with recovery of 50% of the increase in the first year, 75% of the increase in the second year and the full increase included in rates in the third year. Second, Empire recommended that the portion of the revenue increase not included in rates during the first two years be deferred, with a carrying charge, to be recovered over a specified period of time. Making these two changes would ensure that Empire is permitted to recover and earn on the full amount of the investments that have been made, and achieves PUD's goal of spreading the impact of the increase over time.

CHRISTOPHER D. KRYGIER

Mr. Christopher D. Krygier gave rebuttal testimony on behalf of Empire. Mr. Krygier is employed by Liberty Utilities Services Corp. as its Director of Rates and Regulatory Affairs for its electric, natural gas, water and wastewater utilities located in Missouri, Oklahoma, Kansas, Arkansas, Iowa and Illinois. Mr. Krygier testified that Empire appreciated PUD's attempt to mitigate the impact on customer rates, while at the same time recognizing and recommending a needed base rate increase of slightly over $3 million.

Mr. Krygier described the recommendations of the AG and OIEC as the "Kansas Plan." According to Mr. Krygier, AG witness Farrar stated on Page 11 of his Responsive Testimony, beginning at line 12, "For any increased recovery allowed at this time, the Commission should follow the approach employed by the KCC and establish a rider for the recovery of a return and expense increases related to the environmental compliance upgrades to Empire's production plant."

Mr. Garrett set forth OIEC's recommendation as follows:

> "I believe that the Commission could authorize a rider for Empire's collection of the capital costs of the Asbury and Riverton 12 projects, subject to refund and subject to a Commission review for prudence of these investments in Empire's next Oklahoma rate case. All other cost increases should be rejected at this time and could be considered in Empire's next Oklahoma rate filing, which is consistent with the actions of the KCC."

Mr. Krygier further testified that OIEC's calculation uses a pre-tax return of 9.79%, which is OIEC's recommended rate of return, as well as their recommended depreciation rates resulting in a revenue requirement of $804,205. Mr. Farrar utilized Empire's requested cost of capital and existing depreciation rates which resulted in a revenue requirement of $866,968.

Mr. Krygier testified that the Commission should reject the "Kansas Plan". First, accepting the "Kansas Plan" kicks the can down the road on this rate case for a third time. The Company first filed a case pursuant to the reciprocity rule and, then this rate case. The recommended approach by the Interveners would necessitate a third rate case, an action that is not in the public interest. Second, according to Mr. Krygier, the Interveners are "cherry picking" to find the regulatory solution that best fits their perspective. Finally, according to Mr. Krygier, accepting the "Kansas Plan" is single issue ratemaking.

Mr. Krygier stated that the genesis of this current case was a previous case, Cause No. PUD 201600098. That case, which was filed under the electric company reciprocity rule, OAC 165: 5-7-60, requested this Commission to adopt the rates (with a few deductions for solar incentives and some other items) approved by the Missouri Public Service Commission. However, once those rates were approved in Missouri (which was a settled rate case), both the AG and OIEC wanted another rate case to be filed, which would allow Oklahoma specific information to be the basis for rates. Empire worked with the parties and agreed to file the current case.

Mr. Krygier testified that the Interveners are now recommending a proposal that will require the Company file a third rate case to recover legitimately incurred capital investments and increasing operating expenses. A third consecutive rate case is not necessary to evaluate the reasonableness of Empire's request.

As detailed in the Company's initial direct testimony filings, data request responses and contained in Empire's rebuttal testimony, the Company has made significant investments in the utility infrastructure system that are in-service providing benefits to customers today. No party to this proceeding is alleging disallowances based on imprudent decisions by the Company.

Mr. Krygier testified that in an effort to find the lowest possible rate increase, the Interveners are picking a settlement from another jurisdiction to make their case, rather than looking at the facts, Oklahoma accounting data, and circumstances of this case. After rejecting the Missouri settlement, they are now trying to advocate for the Kansas settlement. Mr. Krygier stated that the Kansas case they refer to, Docket 16-EPDE-410-ACQ, was the Company's merger application in a different state. While the merger application did have a connection to the Kansas rate case that was filed, it is a different state with a different set of circumstances. Now, after this unrelated merger case settlement in Kansas, the Interveners are requesting that the Commission ignore the facts presented in the Company's current Oklahoma rate case and adopt the merger related settlement made in Kansas, not a base rate case. Mr. Krygier further testified that their approach to regulatory cherry picking, which is essentially looking for the lowest rate from an unrelated proceeding, is inconsistent with the intended goal of having new rates based on Oklahoma specific accounting information.

Mr. Krygier further testified that the AG's recommendation is single issue ratemaking. Mr. Farrar's recommendation only considers part of the environmental investment, but ignores everything else. This is the epitome of single issue ratemaking.

According to Mr. Krygier, OIEC's recommendation has the same single issue ratemaking concerns as mentioned above in respect to the AG. However, OIEC's recommendations exacerbates [*sic*] the ratemaking issues by asking the Commission to reduce depreciation rates from current rates and lower the allowed return.

Mr. Krygier testified that if the Commission ultimately supports the Interveners' recommendation to implement an environmental rider providing recovery of only the Asbury and Riverton 12 investments, the Company will not be able to earn a reasonable rate of return for its stakeholders. As such, it will be necessary for the Company to file a third application for an increase in rates.

In response to PUD witness Ms. Champion's recommendation that a four year mitigation plan of the ultimately approved revenue requirement be implemented, Mr. Krygier stated that Empire is sensitive to the magnitude of this increase and is willing to work with the parties to find a plan that balances the interests of the Company and its customers.

In Mr. Krygier's opinion, there are two important considerations when evaluating a mitigation plan. First, recovery of uncollected revenue. Second, recovery of interest on that uncollected revenue.

Uncollected revenue is revenue that the Commission authorizes but is not immediately implemented. According to Mr. Krygier, if the Commission were to adopt PUD's recommendation, a rate increase of approximately $3 million would be authorized. If the Commission then accepts PUD's plan as currently outlined, only 30%, or approximately $900,000 of revenue would be collected the first year. The remaining $2,100,000 would permanently not be collected by the utility in year one. Some amount of uncollected revenue would occur in each year of the proposed mitigation plan until the full revenue requirement is ultimately implemented in year four.

Mr. Krygier testified that the Commission should authorize the collection of uncollected revenue for several reasons. First, is that the capital investments and operating expenses used to operate the utility are currently in-service and providing benefits to customers. That means that customers are enjoying the benefit of this infrastructure but are not paying the full cost for it.

Second, if the Company is expected to continue to re-invest into the necessary infrastructure, depriving the utility of the revenues to make that continued investment proves challenging. Finally, as Company witness Mr. Sager describes, not providing the full recovery of uncollected revenue could create accounting implications for the Oklahoma operations.

Mr. Krygier testified that interest on the uncollected revenue is an important consideration. In the example above, $2,100,000 was uncollected, applying the weighted average cost of capital agreed to by the Company and PUD, 7.59%, yields approximately $159,000 on an annualized basis.

In Mr. Krygier's opinion, in addition to the reasons articulated above on the uncollected revenue, it did not seem reasonable to withhold the utility from collecting its fully authorized revenue requirement and also deprive it of the interest associated with the uncollected amounts.

TIMOTHY S. LYONS

Mr. Timothy S. Lyons, a Partner at ScottMadden, Inc., adopted the Direct Testimony of Mr. Bryan Owens.

Mr. Lyons testified that Empire was requesting an overall increase of $3.8 million in Oklahoma jurisdictional revenue, or an increase of 27.58 percent. The increase is based on an overall rate of return of 7.59 percent and a return on equity of 9.9 percent. The primary factors driving the need for a rate increase include capital expenditures associated with the AQCS and related depreciation and property tax expense, capital expenditures associated with the Riverton 12 and related depreciation and property tax expense, normal integrity capital expenditures and related depreciation and property tax expense, increased expense levels associated with plant maintenance, and increased expense levels associated with payroll, pension, and healthcare.

The supporting schedules included in this filing are based on the twelve-month period ending June 30, 2016, adjusted for known and measurable changes.

According to Mr. Lyons, Empire was filing this rate case to adjust its base rates for electric service to more accurately reflect the Company's revenues, expenses, and investments necessary to provide service to its customers. Without the proposed increase, the Company will not have a real opportunity to earn a reasonable rate of return and recover its investment and increased costs incurred since base rates were last revised on January 6, 2012. The Company's current base rates were developed in its last general rate case in Cause No. PUD 201100082 using a test year ending December 31, 2010. While the revenue requirement developed in that case included the Company's significant investment in new generation at the Plum Point and Iatan facilities, the Company has experienced significant other changes since the conclusion of that case.

Since the rates from the Company's last general rate case took effect on January 6, 2012, Empire has made significant capital investments that have not been fully included in electric rates. Empire is also experiencing increases in other costs that, without a rate adjustment, will erode the Company's earnings and undermine its ability to earn a fair return.

According to Mr. Lyons, since January 2011, Empire invested approximately $670 million in total Company capital projects. Of this amount, approximately $122 million (total Company) is related to the AQCS project placed in service December 2014 and approximately $182 million (total Company) is related to the Riverton 12 Combined Cycle conversion project placed in service May 2016. Of the $3.8 million requested deficiency, the AQCS project and the Riverton 12 project represents approximately $1.1 million of the requested revenue increase. Table 1 below summarizes by broad category, total Company investments since January 2011. The Company's property taxes, depreciation, plant maintenance, tree-trimming, salaries, pension, health care, and other operating costs have also increased.

H. EDWIN OVERCAST

H. Edwin Overcast, Director, Black & Veatch Management Consulting LLC, testified on behalf of Empire.

According to Dr. Overcast, cost of service is a necessary element of the rate case process. At the most fundamental level, it provides the revenue requirement necessary to permit the utility to recover the prudently incurred costs of providing service, including a return of and on the capital employed to provide services. When prepared correctly to reflect actual cost causation, the cost of service study is also useful as a guide to allocating costs among customer classes and for determining the rates that provide a utility with a reasonable opportunity to earn the allowed return. It also provides useful metrics for determining if rates meet the just and reasonable and non-discriminatory tests required for rate approval.

Dr. Overcast testified that cost studies are a basic and ultimately a necessary tool of ratemaking. A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs. In addition, utility costs may be fixed or variable costs. Finally, utility costs exhibit significant economies of scale. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective.

Dr. Overcast testified that cost causation is the key element to selecting an allocation factor. This has been the standard by which an allocation method is evaluated and it continues to be the gold standard for assessing cost allocation.

Dr. Overcast further testified that under the traditional embedded cost allocation, the process follows three steps: functionalization, classification, and allocation. This three-step process underlies the determination of cost causation. By identifying the functions of utility service-production or generation, transmission, distribution, and customer for electric service-and the costs of these functions, the foundation is laid for classifying costs based on the factors that cause the utility to incur these costs-energy, demand, and customers. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. If these factors properly reflect cost causation, the cost of service study is a reasonable tool for use in assigning revenue requirements to each class of service.

In many cases, according to Dr. Overcast, it is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase with more kWhs? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system. We also know that the miles of conductor increases with the growth of the peak load on the conductor by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. In any case, the factors driving the cost of conductor are customers and non-coincident peak demand. Following this logical process allows one to determine cost causation.

Despite the simplicity of this approach, it is also necessary to understand key differences as related to cost causation based on the practical engineering and operation of the system. Essentially, there are fundamental differences in the cost to serve the same customer with identical loads depending on any number of factors that cause large differences in cost between urban service and rural service for example. Urban service may have more underground delivery service with higher costs or be served from a three-phase overhead primary looped system with its higher costs than a rural customer served off a single-phase overhead system requiring less conductor and lower cost for overhead poles.

Dr. Overcast testified that cost of service studies use a three-step process that includes functionalization, classification, and allocation.

The process of functionalization requires determining the utility costs associated with each of the functions provided by the utility. The typical functions used in a cost study are production, transmission, distribution and customer service.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

Dr. Overcast testified that once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three factors. That is a utility incurs costs based on (1) the number, size and type of customers, (2) a combination of several measures of customer demand or (3) a measure on the energy used by customers. Within these three classifications there may be different measures of the factor based on how costs are incurred when allocation factors are developed.

Each of these functions is described below.

Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are those costs that vary with number of customers such as meters and service lines.

According to Dr. Overcast, costs can be classified into more than one category. For example, some distribution costs may have both a demand and a customer cost component.

In the allocation process, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that cause the costs to be incurred.

Dr. Overcast testified that costs are functionalized and classified in the study based on data from the Uniform System of Accounts ("USOA"). The cost study uses two types of allocation factors: external factors and internal factors. *External* allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Generation is functionalized to production accounts and allocated based on both an external capacity and energy allocation factor depending on the nature of the account. Transmission costs are functionalized to transmission FERC accounts and are assigned by an external transmission allocation factor. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles, conductors, conduit and transformers are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on an external allocation factor. *Internal* allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore it is necessary to compute the amount of plant by function before property insurance costs can be assigned. Both external and internal allocation factors are used in each of the functional and classification steps outlined below.

Dr. Overcast further testified that the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peak ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods. Within each of these categories, there are numerous specific formulations of the methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of these allocation factors. For example, class non-coincident peaks drive the allocation of part of the distribution system capacity while it is some combination of coincident peaks and demand and energy methods for generation. Within each classification category, there may be multiple specific methods. Under the CP allocation category, options include a single CP, 4 CP, 12 CP, winter/summer CP and so forth.

According to Dr. Overcast, in the case of production, the choice of an allocation factor depends on how costs are incurred for the capacity portion of production costs. It is a basic proposition of reliable utility service that the utility must have adequate capacity to meet the peak load requirements of its customers plus a level of reserves to maintain reliability. This means that peak load causes capacity costs to be incurred. However, when a utility plans its system, it uses a combination of different technologies to meet both capacity and energy requirements by taking into account the system load duration curve as well as peak load. Typically, some units have high capital costs but low operating costs. Units that are designed to run many hours of the year, referred to as base-load units, have the lowest total cost (capital costs and fuel) of any technology for long hours of operation. Units with lower capital cost but higher running costs such as combustion turbines are added to the system to operate flexibly at peak hours and when needed to meet rapidly changing load conditions. The higher cost for a base-load unit is incurred to produce lower annual fuel costs and recognizes that some of the higher capacity cost is offset by fuel cost savings. Under these circumstances, a portion of the cost of a base-load unit is incurred for the purpose of lowering energy costs. Thus, some portion of the capital cost for base load is related to energy. The AED method recognizes a portion of cost is related to energy and the excess cost is a pure demand related cost.

Dr. Overcast described the five schedules that made up his cost-of-service study.

According to Dr. Overcast, the use of the AED/12CP cost allocation methodology is the most appropriate cost allocation method for Empire's production costs. He developed the AED method based on a review of the total demand on system capacity, not simply the system load demand. This is an important distinction because load is not the only demand placed on capacity. Generation capacity must also be maintained and based on certain conditions and may not be fully available to serve load. Also, unplanned outages place a demand on the available capacity. Thus the demand on system capacity is the sum of the load demand to serve customers, the scheduled outage demand for maintenance, the forced outage demand for unplanned outages and the demand that occurs because of weather or operating issues that limit capacity to less than the full output of the generator. Based on the full demand on capacity, the appropriate AED allocation factor consists of average demand (energy divided by 8760 hours) and the excess demand based on twelve coincident peaks (12 CP). AED/12CP reflects cost causation for the system based on all of the operating characteristics of the system. The excess demand component is allocated on the class NCP.

Dr. Overcast further testified that a part of the cost study review was to evaluate the total demand for capacity on the Empire system. Table 1 shows the total monthly system demand on capacity resources, and the following bar chart illustrates the total demand on capacity for the system based on the maximum demand occurring in each month of the year. The line on the graph shows the average total demand for the system and the months that exceed the average of the total demand.

Table 1
Total Monthly System Demand on Capacity Resources[1]

Month	MWH
January	1,149
February	1,057
March	907
April	638
May	749
June	1,026
July	1,094
August	1,039
September	951
October	707
November	704
December	812

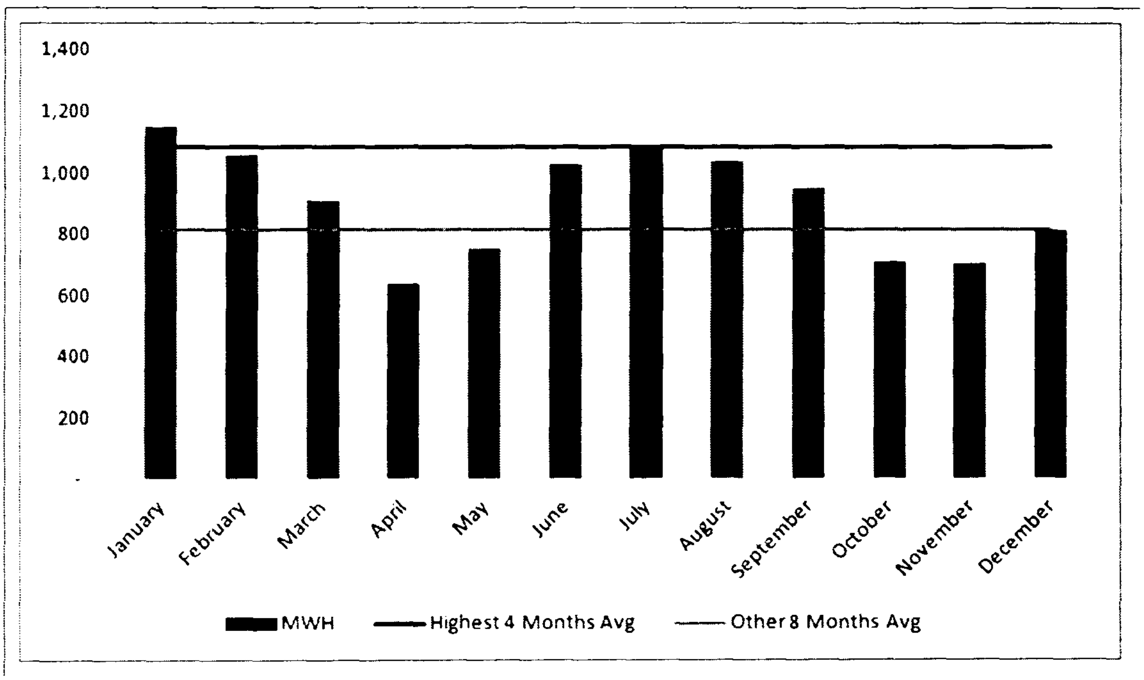

Table 1 provided guidance on the selection of the appropriate number of months to be used as the system peak in the preferred AED method for allocating production capacity that he utilized in Empire's case. If we add to the load demand scheduled maintenance, forced outages and unit deratings, the monthly demands flatten out because maintenance is scheduled in low use months. The data shows that Empire is a dual peaking utility in the summer and winter for load. The actual system peak may change with weather during a calendar year. Typically unit deratings occur in the summer and would add to the peak load in those months. Forced outage rates vary and as noted above, maintenance is scheduled in spring and fall months. Based on these facts, peak total demand falls in a narrow band for all 12 months. He defined the system peak for the AED method based on the 12 CPs for Empire.

According to Dr. Overcast, the AED allocation factor was made up of two components: (1) the system average demand and (2) the system excess demand. The following formula is used to calculate the AED allocation factor for each rate class.

$$\mathbf{APCC_i}=((\mathbf{E_i}/8760)/(UE/8760))*((UE/8760)/UCP) + ((\mathbf{NCP_i}\text{-}\mathbf{AD_i})/((\textstyle\sum_{i=1}^{c}\mathbf{NCP_i}) - UAD)))*(1- (UE/8760)/UCP)$$

Where $\mathbf{APCC_i}$ equals the allocation percentage for the i^{th} customer class. $\mathbf{E_i}$ equals the energy consumption of the i^{th} customer class. $\mathbf{E_i}/8760$ equals the average demand of the i^{th} customer class also denoted by $\mathbf{AD_i}$. UE equals the total energy for the utility and UE/8760 equals the utility average demand also denoted UAD. UCP equals the utility coincident peak or peaks. (UE/8760)/UCP equals the utility's annual load factor. $\mathbf{NCP_i}$ is the class non- coincident peak. $\mathbf{NCP_i}\text{-}\mathbf{AD_i}$ is the class excess demand for the i^{th} customer class. $\sum_{i=1}^{c}\mathbf{NCP_i}$ is the sum of the class non-coincident peaks for the classes. UAD equals the utility average demand. $((\sum_{i=1}^{c}\mathbf{NCP_i})$ - UAD)) equals the utility excess demand. (1- (UE/8760)/UCP)) equals 1 minus the utility load factor. Stated in words rather than by formula, the AED allocation factor is the sum of the class average demand as a percent of the system average demand weighted by the system load factor and the class excess demand defined as the difference between the class average demand and the class non-coincident peak demand as a percent of the system total excess demand defined as the sum of the classes non-coincident peak demands less the system average demand times 1 minus the utility load factor as the weight of the excess component. The peak used to determine excess demand may be the average of more than one hour. For example AED/12CP would determine the system excess demand using the average of the highest 12 monthly peaks. Using multiple months to determine the excess demand has the effect of weighting the average demand component more than using a single peak. The choice of the factor to determine the excess demand is based on an analysis of the total demand on the system, not just load demand.

The allocation of excess demand using NCP is a critical component of the AED allocation. If one were to use the CP allocator instead on the NCP, the allocation becomes the mathematical equivalent of the CP allocation factor. As described above, the AED/12CP is the option that best meets the criteria of cost causation.

Dr. Overcast testified that the transmission Plant was allocated based on 12 CP. The use of 12 CP reflects the use of Transmission Plant on a monthly basis. Absent significant differences in monthly loading of the transmission system, such as high summer peaks and low winter peaks, a 12 CP allocation factor is consistent with the design and use of Transmission Plant. For Empire, winter and summer peaks are very close in terms of load. Further, the transmission system is designed to move generation output from the generation nodes on the system to the load nodes on the system and off the system when dispatched for the SPP. At any one time, the capacity of the system must be such that load nodes have access to adequate generation, including the purchase of power to lower costs or to assure reliability at each load node. The fact that different load nodes peak at different times and that a different combination of resources serves the node means that transmission capacity is used differently over time and that the monthly peaks represent the best reflection of cost causation as opposed to the system peak load periods only.

Next, Dr. Overcast testified regarding the allocation of distribution plant. Distribution Plant includes substations, poles and wires, transformers, meters, and services. In addition, Distribution Plant includes lighting. The allocation of Distribution Plant requires that the investment be classified as demand or customer, since these are the two factors that cause the cost. For distribution costs found in Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 - 373 are not customer related. For Account No. 369- Services, each customer has a service designed to meet that customer's own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition, Account Nos. 371 - 373 represent facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 - 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

Dr. Overcast further testified that it was important to understand the role of scale economies in distribution service when allocating costs and designing rates for delivery service. The cost of distribution facilities declines per kWh consumed for any given level of demand. For example, the cost of facilities such as transformers has a lower per unit of demand cost for higher demands. The following table provides data for a range of transformers that may be installed for residential customers and the cost per kVa of each size of transformer.

Table 2
Cost per kVa of Transformer Capacity

Single Phase Transformer	Installed Cost	Cost per kVa
15 kVa	$1,342.97	$89.53
25 kVa	$1,600.57	$64.02
50 kVa	$2,167.86	$43.36
75 kVa	$2,678.73	$35.72

The above table illustrates the cost per kVa of transformer capacity declines dramatically as the size of the transformers increases. For customers with an NCP below 10 kW, the unit cost is over twice as much as for customers served off a 50 kVa transformer. Since a 15 kVa transformer is the minimum size installed based on engineering standards for the Company, smaller customers served off this transformer cost more to serve per unit of NCP than do larger customers served off larger transformers. This same phenomenon occurs for other elements of the distribution system including poles and conductor.

The implications for cost of service are that customers with higher NCP may actually have lower total costs than smaller customers. Compare two customers as follows: first, a customer with central air conditioning and an electric water heater with an NCP of 12 kVa and second, an all-electric customer with an NCP of 17 kVa. Further assume that the all-electric home is in a subdivision where three homes are served off a 50 kVa transformer. The total cost of transformer capacity is about $723 each for the all-electric homes and $1,342.97 for the smaller demand customer's home. When recovering the cost from each customer, it is necessary to take into account the relative load factor of each customer since the greatest portion of fixed costs are recovered volumetrically. The typical all-electric home has a higher load factor based on NCP than the typical non all-electric home, resulting in an even lower cost per kWh for the all-electric home. In addition, the all-electric home has a much higher CP load factor when the system peaks in the summer like it does for Empire. On a CP basis, the rates for the all-electric customer should be substantially lower than the other customers. This is the fundamental basis for declining block residential rates and demonstrates that such rates are cost based.

Dr. Overcast testified that distribution plant was classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (USOA 360-363), the plant is classified as demand and is allocated on the class contribution to the system NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines (USOA 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation, the demand allocation is based on the sum of the customers NCPs for each class of service. For the remainder of the distribution accounts (USOA 369-373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible.

According to Dr. Overcast, there were also other costs that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of an account is allocated as customer related, all of the O&M costs should also be allocated to customer costs. Second, customer service related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores and tools and equipment. Fourth, a portion of administrative and general expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

Dr. Overcast testified that the following two tables provided a high level summary of the results of the cost of service study.

TABLE 3
RATE OF RETURN BY RATE CLASS

Rate Class	Rate of Return
Residential	-1.36%
Commercial	6.39%
Total Electric Building	5.27%
General Power	7.70%
Power Transmission	2.17%
Street Lights	-0.73%
Private Lights	39.76%
Spec Lights	-11.79%
TOTAL SYSTEM	2.28%

TABLE 4
REVENUE DEFICIENCY OR EXCESS BY RATE CLASS

Rate Class	Revenue Excess (Deficiency) (000s)
Residential	($2,326)
Commercial	**($215)**
Total Electric Building	($52)
General Power	**($195)**
Power Transmission	($1,087)
Street Lights	**($36)**
Private Lights	**$102**
Spec Lights	**($11)**
TOTAL SYSTEM	($3,819)

According to Dr. Overcast, the cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Other considerations include principles such as gradualism or avoiding rate shock, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Dr. Overcast testified that he proposed no decreases to any rate class. For classes with largest deficiencies, he proposed increasing the class by approximately 125% of the average increase, or a 55% increase in base rates. These classes include residential, transmission service, streetlights and special lights. He proposed no increase for the private lighting class, and for all other classes to allocate the remaining revenue deficiency uniformly to each class.

The proposed allocation reflects the principal of gradualism. It is consistent with moving classes toward a more uniform rate of return.

Dr. Overcast recommended that the rate design change for all rate schedules except private lighting.

According to Dr. Overcast there were a number of significantly important issues with respect to Empire's currently authorized rate design. First, Empire's current rates place far too much reliance on volumetric recovery of fixed costs. Second, the current rate designs do not provide Empire a reasonable opportunity to earn its allowed return in the face of events beyond the Company's control, such as weather and conservation. Third, the rates that consist of a customer charge and volumetric charges do not properly assign costs to the cost causer. Fourth, current rates are not economically efficient, with the result being inefficient use of resources resulting from incorrect price signals.

Essentially, when fixed costs are recovered volumetrically, the utility is at much greater risk for revenue recovery. The revenue recovery risk is significant because the competition for capital in the market place causes Empire to be at a disadvantage relative to other electric utilities with more revenue certainty as the result of different regulatory policies.

The percentage of total revenue under current rates recovered through volume related charges (kWh) was 81.07% for RG; 84.28% for RH; 88.50% for CB; 91.90% for TEB, 67.27% for GP; and 71.89% for PT.

There are a number of reasons that volumetric rates in conjunction with other regulatory policies fail to provide the utility with a reasonable opportunity to earn the allowed return. Volumetric rates provide no revenue stability for the utility, since the bulk of non-energy costs do not change with volume, and any change in kWh from the weather normalized volume of sales will inevitably produce either too much or too little revenue.

Dr. Overcast testified that Empire's current rates do not appropriately assign costs to the cost causers.

Since rates based on kWh charges collect more revenue from the larger customers in the class for essentially the same costs, or in some cases even lower, total fixed costs. In the case of residential customers, the customer costs are the same on average, but are not all recovered in the customer charge. In this case, the residential customer cost based on the historic actual year used in the cost study is $41.19 per customer. Even at a proposed customer charge of $20.59, and assuming that the total kWh charge is available to compensate Empire for the customer costs, customers who have average use less than 222 kWh per month do not even pay the full customer cost. Further, the customer would not make any contribution to the fixed costs for production and transmission that is over $25.63 per kW, and that value on a per kWh basis at a 40% load factor is about $0.088. This essentially means that the smallest residential customers never pay the full customer costs, if we assume the customer cost is a residual calculation. Excess customer costs are recovered in the kWh charge, causing larger users to bear a disproportionate share of those costs. The same concept applies to distribution related costs where scale economies result in lower per unit costs for larger customers. For transmission and generation fixed costs, the average total cost per unit of demand is the same for all customers in the class. Volumetric recovery means that higher load factor customers bear a disproportionate share of those costs relative to lower load factor customers. In the residential class, both of these factors demonstrate that larger customers have lower unit costs and, in some cases, lower total costs than smaller use customers. It follows that collection of the revenue requirement through volumetric charges that recover fixed costs results in larger use customers paying far more of the fixed costs than the customers cause. There is also the possibility that some larger customers even pay more for energy and subsidize other customers because of the seasonal and diurnal pattern of their use. This type of intraclass cost subsidy for similarly situated customers should be addressed by the Commission.

According to Dr. Overcast, the most efficient rate design begins by fully unbundling costs in a way that matches billing with the factors that cause cost. Empire has already started this process with the recognition of the different cost drivers for distribution demand by instituting the facilities demand charge in some jurisdictions that recovers distribution related demand costs in those classes with demand metering. Empire has also moved certain customer charges to levels that reflect the customer costs for that class of service. These are important initial steps in the unbundling of costs. Nevertheless, further unbundling is also an important step. Under full unbundling, the rate components are as follows:

- customer charge;
- generation demand charges;
- transmission demand charge;
- distribution substation service demand charge;
- distribution primary service demand charge (with and without transformation at the delivery point);
- secondary distribution demand charge for amounts not included in the customer charge;
- energy service at transmission voltage;
- energy service at substation delivery;
- energy service at primary delivery with and without transformation; and,
- energy service at secondary voltage.

Energy and certain demand related charges may also be seasonal and time differentiated. Each of these charges is based on a different cost driver, and some of these costs may be combined where the utility cost characteristics dictate similar treatment for some components.

Empire proposes to begin moving in this direction by taking initial steps such as moving customer charges either to the customer cost or toward the customer cost where the consideration of gradualism is appropriate. Empire can also put more emphasis on cost recovery in demand charges for customers with demand meters.

Dr. Overcast further testified that the residential class (rate RG) has limited options for implementing the demand charge components based on the existing metering available. In this case, as part of a gradual move to more efficient rates, the customer charge is proposed to increase by approximately 65% above the current level. In addition, per kWh charges increase slightly to recover the remainder of the necessary class revenue increase. These kWh charges remain far too high, but, with the customer charge increasing 65% above the current level, the per-kWh increase is necessary. The first block of 0 to 50 kWhs has been eliminated and added to the second block subject to a full first block charge. This is done since there is no rationale for having some level of kWh use included in the customer charge making the rate even less efficient.

There is little other opportunity in the residential class, although it may be possible to have a distribution facilities charge based on the maximum monthly consumption in the past year by using the average NCP by load research strata times the dollars per kW of unbundled cost at about $5.00 per month for customers in each strata based on the last twelve months of use. This would reduce the energy related charges and recover the cost as a graduated demand charge based on annual system use in six strata. This could serve as a proxy for facilities demand in classes with kWh billing. Consideration should be given to the inclusion of a facilities demand charge being included in the kWh only rates.

Dr. Overcast testified that for all of the remaining rates except lighting, he recommended the increased customer and demand charges. In addition, he recommended that each other rate schedule excluding the lighting schedules have the customer charges adjusted toward the unit customer costs. There is no proposed increase in kWh charges for these schedules.

In rebuttal, Dr. Overcast testified that he agreed with PUD witness Mr. Schwartz. His review of the cost study was extremely detailed. Based on that review, Dr. Overcast noted that Mr. Schwartz accepts the use of the Company's production and transmission allocation factors. This is significant for the fact that PUD obviously understood the precedent that Mr. Garrett has relied upon to reject the Company's proposed allocation factors for production and transmission. PUD obviously recognizes that no two utilities are alike and cost causation is unique to the circumstances of each utility and thus may warrant different allocation factors. According to Dr. Overcast, the differences between the Empire system and other utilities warrants approval of the COSS as filed by Empire.

Dr. Overcast testified that Mr. Garrett relied on Commission precedent for other large electric utilities in the state to propose changes in the production and transmission allocation factors in the Empire COSS. That reliance is misplaced. In fact, since no two utilities are alike, it is necessary to understand the factors causing costs for each individual utility. No generic allocation methodology can be applied to every utility because of the differences that exist. Witness Garrett himself recognizes this fact as he has used a different 4CP allocation factor than is used by the other two electric utilities he cites in his testimony. The use of two winter and two summer months for 4CP as opposed to the four summer months used for Oklahoma Gas and Electric ("OG&E") and Public Service of Oklahoma ("PSO") is admission that Empire is different than both those utilities. Mr. Garrett fails to recognize how fundamental differences impact the decisions about cost causation.

Dr. Overcast testified that in Kansas, he filed cost studies for both Westar and Empire. For Westar, he used the AED/4CP methodology, while he used the same AED/12CP methodology for Empire that he used in this cause. The rationale for different production allocation factors is based on the total capacity demand on the system, which is the correct way to determine cost causation. It is incorrect to only consider load as Mr. Garrett recommends. Mr. Garrett's approach is also inconsistent with FERC standards for determining the appropriate peak allocation factor. FERC standards require that the utility consider "the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments." Empire's cost study has followed this rigorous process.

System planners use more than customer load when they analyze the need for capacity. A simple example illustrates this point. A utility may be winter peaking for load but may plan its system based on summer peak requirements. The reason is that some generation may need to be derated (the kW capacity at full output is lower) in the summer because of ambient temperature. On paper, the utility has more kW of installed capacity than it needs to meet the summer load but because the nameplate capacity is reduced in the summer it has inadequate capacity to meet that load. Utilities also evaluate forced outage rates and scheduled maintenance as part of their planning analysis of capacity including required reserves. It is even possible that a system with a relative flat load curve (operating at a high load factor) could require additional capacity in lower load months in order to be able to schedule maintenance. Mr. Garrett effectively ignores the total demand on capacity and focuses solely on the peak loads in two winter and two summer months. His choice of only two summer months belies the fact that three of those months are over 1000 MWs of load. 4CP is just an arbitrary use that cannot be logically supported for an Empire cost study.

Dr. Overcast analyzed the total demand on capacity for Empire.

Dr. Overcast requested that Empire run its system dispatch model that is used by system planners to determine the total demand on capacity for each month of the year. That demand is the sum of customer load, scheduled maintenance, forced outage rates and unit deratings. Table 1 below shows those values.

Table 1
Monthly Total Capacity Demand

Date	Peak Load	Generating Capacity	Unit Derating	Wtd. Scheduled Maintenance	Assumed Wtd. Forced Outage	Peak Plus Outages
Jan	1,134	1,602	0.00	-	137.56	1,271.93
Feb	1,070	1,602	0.00	-	137.56	1,207.13
Mar	866	1,568	34.00	235.48	134.29	1,269.73
Apr	718	1,535	67.00	408.77	131.02	1,324.60
May	737	1,535	67.00	150.06	131.02	1,085.24
Jun	1,089	1,467	135.00	4.00	124.48	1,352.94
Jul	1,093	1,467	135.00	-	124.48	1,352.64
Aug	1,115	1,467	135.00	-	124.48	1,374.59
Sep	1,027	1,467	135.00	-	124.48	1,286.43
Oct	720	1,535	67.00	239.29	131.02	1,157.35
Nov	814	1,568	34.00	208.17	134.29	1,190.40
Dec	1,034	1,602	0.00	-	137.56	1,171.73
					Average	1,253.73

As expected, scheduled maintenance dramatically increases system demand on capacity in low load months like March, April, October and November. The resulting nearly flat load supports the claim that consideration of total system impacts supports the use of AED/12CP.

Dr. Overcast further testified that he had reviewed the loads for both PSO and OG&E. Table 2 compares the 2015 peak loads among the three utilities. It is easy to see that the demand peaks for both PSO and O&GE differ from the Empire pattern because they are not dual peaking systems. Coupled with the data for Empire in Table 1 the use of AED/12CP is fully supported by the facts unique to Empire.

Table 2
Monthly Peak Load Comparison

Month	Empire Monthly Peak	PSO Monthly Peak	OGE Monthly Peak
	MWh	MWh	MWh
January	1,149	2,974	5,084
February	1,057	2,804	4,801
March	907	2,722	4,716
April	638	2,578	4,182
May	749	2,901	4,623
June	1,026	3,795	5,866
July	1,094	4,015	6,269
August	1,039	4,164	6,537
September	951	3,749	5,996
October	707	2,979	4,891
November	704	2,264	3,867
December	812	2,428	4,251

Empire has seven months of peak loads above 79% of peak load while both PSO and OG&E have only four months of load above 79%. Load is not the full demand on capacity and it is the totality of the operating realities of the system that must be considered to determine cost causation.

Dr. Overcast further testified that Mr. Garrett's argument for a 4CP allocation factor does not reflect cost causation. Empire transmission costs are allocated to the Oklahoma jurisdiction on 12CP. There is no reason to use 4CP when the costs that flow to Oklahoma jurisdictional customers are based on 12CP as the cost causation factor. Further, Empire has an approved FERC formula rate for transmission costs under SPP that is based on 12CP. (*See* Open Access Transmission Tariff, Sixth Revised Volume No. 1 --> Attachment H Annual Transmission Revenue Requirement For ... --> Attachment H Addendum 18 (Empire)).

In sum, there is no basis for concluding that transmission plant should be allocated on 4CP to retail customers when costs are all the result of 12CP factors for the Empire system. Mr. Garrett is wrong on the facts that support the careful analysis of cost causation that underlie the Empire COSS.

Regarding revenue allocation, Dr. Overcast testified that the allocation of revenue requirements among the classes of service is always a contentious issue. The factors that should be considered by the Commission do not provide a clear basis for a revenue allocation policy. For example, cost of service studies are not perfect instruments for determining the actual revenue responsibility of a class of service. That is, the resulting values are always subject to some margin of error in the development of allocation factors absent full hourly metering for all customers. The final allocation decision always rests with the Commission in any event.

Dr. Overcast recommended a 25% increase above the system average in recognition of the negative returns. He understood the Commission's desire to minimize the size of the increase while at the same time making some movement toward reasonable cost recovery from each customer class. He suggested that the revenue allocation proposed by Mr. Schwartz in Figure 3 represented a reasonable level of allocation among the classes.

Dr. Overcast also addressed PUD's recommended phase-in of the rate increase. He believed that a workable phase-in of the rate increase is a reasonable solution to reducing the immediate magnitude of a significant rate increase. The issues that need to be addressed for an acceptable phase-in include the number of years to fully recover the revenue requirement authorized in this rate proceeding, the carrying charge rate applied to the unrecovered balance, the true up process to assure full recovery of the costs during and at the end of the true-up period and the rate design factors to be considered as the future dollars are added to rates. A shorter phase-in results in lower total revenue requirements for customers based on lower carrying charge revenue requirements associated with unrecovered balances that must be amortized in rates.

Failure to recover the carrying charge associated with unrecovered balances in the rate year effectively means that the Company and its shareholders must finance those costs until they are recovered in the future.

Dr. Overcast testified that since there are no billing determinants for the period beyond the test year, it will be impossible to set rates that provide either a reasonable opportunity to earn the allowed return or to match revenues in any year to the share of increased revenue requirement for that year. The simple solution is to set up a balancing account that will add to or subtract from the approved revenue the actual revenue in each period and add to or subtract from that amount in a balancing account to assure Empire of full rate recovery during the transition period.

According to Dr. Overcast, the final rate design will be to add the actual revenue approved, less carrying charges and true-up provisions, to the base rates established initially using the approved test year billing determinants. This rate can be filed as part of the compliance filing for the first year's phase-in amount. Essentially, the Company will file a rate for the first year of the phase-in and another rate for the full revenue requirements that will be applicable after the phase-in.

Dr. Overcast provided rebuttal testimony regarding rate design. According to Dr. Overcast, Ms. Champion asserts that the Company proposal "violates an essential principle of rate design: rate stability." This Bonbright principle is one of ten attributes of a sound rate structure. It is certainly not an essential principle as Bonbright does not mention the concept in his three primary criteria for rate design. Bonbright himself recognized that this list of ten attributes suffered from ambiguities, inconsistencies and failure to offer any basis for establishing priorities.

Bonbright also makes it clear that these principles are "based on simplified assumptions as to the objectives of ratemaking policy and as to the *factual circumstances under which these objectives are sought to be attained.*" (Emphasis added.) Ms. Champion errs in relying on this principle for several reasons based on factual circumstances. To begin, she misstates the principle by omitting the word seriously in front of adverse in her restatement of the principle. Thus, we have a minimum of seriously adverse impacts under factual circumstances that increase rates even by the PUD's support of 33%. Further, the simple fact is that the unit cost for the customer component of the residential rate is over $41.00 per month to cover costs that are customer related and the actual energy related costs are recovered through the FAC. All of the remaining revenue requirements for a residential customer are fixed demand or customer related costs that are recovered volumetrically. In the proposed tail-block (over 600 kWh) of Ms. Champion's final rate design, the portion representing fixed cost recovery is over $0.08 per kWh in the summer and $0.06 in the winter. These values are far in excess of short-run marginal costs that should be the basis for an efficient price signal. The short-run marginal cost that is based on volume for the non-fuel costs is zero given the potential for growth in the service area is insignificant and does not require new capital investment. Actual average short-run marginal costs for 2016, based on the Empire load node in SPP, was $0.02423 per kWh. The median value of marginal cost was lower at $0.02143 per kWh and the average marginal cost of the highest 1000 hours in the year was less than $0.037 per kWh. Since these costs are recovered in the FAC and transmission adjustment rider, there is no need to increase kWh charges at all. The Empire proposal is necessary to limit the increase in kWh recovery of fixed costs as much as practical and to begin a transition to more efficient rate designs.

According to Dr. Overcast, economic efficiency results from kWh prices that reflect short-run marginal costs. Alfred Kahn states "it is short-run marginal cost to which price should at any given time—*hence always*—be equated, because it is short-run marginal cost that reflects the social opportunity cost of providing the additional unit that buyers are at any given time trying to decide whether to buy." (Emphasis added.) Severin Borenstein of the Energy Institute at the Haas School at UC Berkeley reaches the same conclusion when he states "The idea that economic efficiency is maximized when price reflects full short-run social marginal cost (SMC) is a bedrock principle of microeconomics." The customer charges proposed by Ms. Champion and Mr. Farrar result in kWh charges far above the short-run marginal cost and hence are inefficient.

The resulting two-part rate design would consist of a marginal cost based unit charge and a fixed charge equal to the dollars per customer to raise the revenue requirements. It is this relationship of price to marginal cost that is the basis for determining if the customer charge allows the utility to send a proper price signal.

Dr. Overcast further testified that Ms. Champion failed to even note that Bonbright reduces his list of ten attributes to three criteria as follows: Criterion 1 – Capital Attraction; Criterion 2 – Consumer Rationing; and Criterion 3 – Fairness to Ratepayers. After a discussion of these three principles, Bonbright discusses cost of service as a basic standard and states "Without a doubt the most widely accepted measure of reasonable public utility rates and *rate relationships* is cost of service." (Emphasis added.) The cost of service in this cause supports a $41 customer charge and no increase to any energy charges for the classes with demand charges. Certainly Bonbright and economists in general would approve of the Company's proposed rates as discussed further below.

Dr. Overcast testified that Ms. Champion's proposed worked against the capital attraction principle by collecting even more proportionally of the fixed costs in volumetric charges price response by consumers in all classes will reduce the earnings of the utility by every dollar saved by residential, small commercial, total electric buildings and every dollar of the kWh charges saved for all of the customers billed on three part rates through energy efficiency, distributed generation or other competitive offerings between rate causes. Empire fails to have a reasonable opportunity to actually recover all the lost fixed costs loaded in the kWh charges. Earnings below the allowed return make it more difficult for the utility to attract capital and increase the risk for investors.

According to Dr. Overcast, consumer rationing means that approved rates should "discourage the wasteful use of utility services while promoting all use that is economically justified" through application of economically sound rate designs. (Emphasis added.) By charging marginal kWh prices that far exceed marginal cost, that impact promotes investment in solar DG facilities that are not cost effective absent the subsidy, investments in energy efficiency that are not cost effective without the subsidy and inhibits the use of electric service in applications where it would be cost effective and environmentally beneficial. As a result, customers choose an option that is not economically efficient and make investments that result in wasteful use of the Empire utility system and the resources of Oklahoma and society in general. The resulting cost shifts from customers who invest in alternatives that are otherwise not economic raises non-participants rates even further above marginal cost and prevent the optimum use of utility facilities. In the absence of optimal use of utility facilities, Ms. Champion makes a recommendation that is contrary to the purposes of the Public Utility Regulatory Policies Act ("PURPA"). Her recommendation also is contrary to the Oklahoma First Energy Plan which states in the introduction that "New markets will develop *as capital flows to the most efficient uses*, and *consumers, opting for maximum utility and value, will vote with their purchases*." Under the rate design proposals of Ms. Champion and Mr. Farrar, capital will not flow to efficient uses as the result of energy prices that are far in excess of marginal cost and consumers will indeed vote with their purchases that will not result in maximum value for the state's electric consumers. In fact, the opposite will be true. There will be larger losses in social welfare as a result of misallocation of resources. Given the magnitude of divergence from marginal costs there are significant welfare losses.

Dr. Overcast testified that based on the results of the cost study that shows over $41 of customer costs and a recommended $15 customer charge by Ms. Champion, larger customers are subsidizing smaller customers in her proposed rates. This means that the intra-class burden is not distributed according to two bedrock principles: cost causation and matching. Given the transition of the electric business to mixed monopoly and competition market, it is imperative that Commissions move away from inefficient rate designs and develop more unbundled, granular rates without subsidies. The Empire rate design proposal moves toward that result while Ms. Champion's proposal perpetuates rate designs that are inefficient, wasteful and unfair to consumers.

Dr. Overcast cited academic support for his rate design proposed.

In discussing rate equity the late Alfred Kahn wrote "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[4] Kahn also concludes that customers typically recognize the equity of paying charges based on cost of service. Since customer costs do not vary with kWh consumption, equity actually requires that all customers, regardless of kWh consumption, pay a charge equal to the costs. In addition, in Utility of the Future - An MIT Energy Initiative Response to an Industry in Transition (MIT 2016) discusses the pricing issue in detail and concludes that the only criteria met by rate design in practice is the recovery of revenue requirements and decidedly not the criteria of allocative efficiency. That same study notes that "Efficient prices and charges are key to lowering overall costs of electricity services, which benefits customers in general." In contrast, Ms. Champion states that "the Company has also ignored the beneficial purpose of higher volumetric changes, essentially to provide conservation price signals to customers and enable customers to control their bill through response to those signals." The irony of this view is found in the simple fact that the only view of conservation expressed in this statement is that conservation results in reduced use at a cost that is only economic for customers because the energy price is substantially above marginal cost. In that event, resources are wasted as noted above relative to the Oklahoma First Energy Plan. The rates proposed by Ms. Champion are decidedly anti-conservation and should not be the basis of the rates approved in this cause.

According to Dr. Overcast, in his opinion, it was ironic that both witnesses want the Commission to rely on decisions by other state commissions as a basis for reviewing the facts in this cause. There is ample evidence from a number of comparable utilities in the state of Oklahoma that when customers are left on their own to determine customer charges higher customer charges are the norm. The simple fact is that Empire in Oklahoma has a service territory that looks more like an electric cooperative than an investor owned utility. With only about 4700 customers (the number for the rate cause) the Empire service area has about one-fourth the customers of the average Oklahoma cooperative and is smaller than all but one of the state's electric cooperatives. Simply, Empire in Oklahoma is more like a cooperative than an IOU. Looking at the Oklahoma cooperatives with their more rural service areas, the average customer charge exceeds $20.00 per month. Table 3 below provides data for Oklahoma cooperative customer charges that customers themselves approve.

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[4] Kahn, Op. Cit. p. 158

Table 3
Oklahoma Electric Cooperative Customer Charges

Alfalfa Electric Coop, Inc.	$18.00		
Arkansas Valley Electric Cooperative Corporation	$16.00		
Caddo Electric Coop, Inc.	$29.00		
Canadian Valley Elec Coop, Inc.	$16.50		
Central Electric Cooperative	$25.00		
Choctaw Electric Coop Inc.	$15.25		
Cimarron Electric Coop	$19.00		
Cookson Hills Elec Coop, Inc.	$25.00		
Cotton Electric Cooperative, Inc.	$30.00		
East Central Oklahoma Electric Cooperative	$17.50		
Indian Electric Cooperative	$25.00		
Kay Electric Cooperative	$20.00		
Kiamichi Electric Cooperative	$23.00		
Kiwash Electric Coop, Inc.	$33.66		
Lake Region Electric Cooperative, Inc.	$27.00	$37.00	Over 200 Amp
Northeast Oklahoma Electric Cooperative, Inc.	$23.00		
Northfork Electric Cooperative, Inc.	$35.00		
Northwestern Electric Coop Inc.	$25.00		
Oklahoma Electric Coop Inc.	$18.00		
Ozark Electric Cooperative	$18.00		
Red River Valley Rural Elec Assn	$21.00		
Rich Mountain Elec Coop, Inc. (Oklahoma)	$13.65		
Rural Electric Cooperative	$14.00		
Southeastern Electric Coop Inc.	$20.00		
Southwest Rural Elec Assn Inc.	$25.00		
Tri-County Electric Coop, Inc. (Oklahoma)	$20.00		
Verdigris Valley Electric Cooperative, Inc.	$30.00		
AVERAGE	**$22.32**		
Maximum	$37.00		
Minimum	$13.65		

Lake Region Electric Cooperative is located in the eastern part of the state and essentially has two customer charges depending on the size of the service (200 amps or over 200 amps) both of which are much higher than the proposed Empire customer charge for regular and all electric residential customers. Homes with over 200 amp service would likely be all electric or have multi-zone cooling. This is consistent with the Company's proposal of a higher customer charge for electric space heating customers.

The Empire service area is within the service area of Northeast Oklahoma Electric Cooperative, Inc. bordered on the south by Lake Region Electric Cooperative, Inc. and to the west by Verdigris Valley Electric Cooperative, Inc. Collectively these three cooperatives have residential customer charges ranging from $23 to $37 per month and an average of over $29 per month. The reasonable conclusion is that the Company's proposed charges are not only just and reasonable but are consistent with customer charges prevailing in the region where the Empire service territory is located. This is particularly true when one considers that customers at the border of the Empire service area have neighbors whose customer charges will still be higher that the Empire charge.

Dr. Overcast testified that the percentage increase in the customer charge was not the relevant measure for determining if the customer charge is reasonable as suggested by Mr. Farrar. The percentage increase to a small number may be quite large.

Dr. Overcast commented on Ms. Champion's bill comparison analysis.

Using monthly bill frequency data to analyze bill impacts requires filtering to get a sample that represents actual customers. For example, there are 847 RG residential bills for zero kWh. It is unlikely that these are actual customers and are more likely vacant premises. In the CB class the number of zero bills is 1029. This is a relatively significant percentage for such a small class of customers with 9411 total bills in the test period. In addition for both classes, there are a number of customers with less than twelve months of bills that implies prorated bills for both a beginning and an ending month that are likely not representative of an actual full month bill. For example, it is relatively easy to show that an occupied residential RG premise is not likely to have monthly consumption under 300 kWh. In the residential RG class, there are over 2500 bills for premises that use under 100 kWh. This is not possible for an occupied dwelling since the smallest refrigerator uses 100 kWh per month and dwellings would also have lights and other miscellaneous appliances. Ms. Champion recognized this in her analysis and used 300 kWh as the smallest bill for residential RG. Understanding the end use appliance mix is very important since adding an electric water heater to a premise would add several hundred kWhs per month to that minimum load. Demographics also plays a role in premise use as more rural customers typically do not have public water supply and rely on a well with a pumping load that adds to premise consumption. Similar issues relate to the CB class where customers who use just a few kWhs per month are not typically an occupied premises but an empty store front using only a security light or security system. The end result is many of the largest increases are not to the year round utility customers or even tenants in an occupied commercial premise. he would not rely on her monthly data as representative of the bulk of customers.

Dr. Overcast testified that for a three year phase-in, it is possible to minimize the impact on customers as follows:

1. Year one Phase-in increases for all of the rates by the proposed customer charges for rates with proposed customer charge increases. For rates without a customer charge increase the demand charge by the amount necessary to equal one third of the increase allocated to the class or in the case of lighting by the increase necessary to match the required phase-in dollars.

2. Year two Phase-in calculate the kWh increase to produce the second year amount including the applicable carrying charge rate for year one and year two plus or minus the true-up adjustment.

3. Year three Phase-in calculate the rates with the proposed customer and demand charges and the percentage increase to lighting rates to produce the full revenue requirement plus year three carrying charge and a true-up adjustment.

4. Year four filed rates that produce the revenue requirements based on test year volumes and full rate relief.

Under this process, Empire will be made whole for the phase-in and will set rates at the full approved level using the proposed customer charges for kWh rates with the kWh charges increasing to recover the class revenue requirement. The rates with demand charges where no kWh charge increase is warranted will have demand charges that produce the revenue requirements.

Dr. Overcast further testified that the proposals of these two witnesses are not supported by the facts in this case, by economic theory, by Bonbright's three primary rate design criteria, by modern academic research in rate design, by PURPA or by the Oklahoma First Energy Plan. Essentially, there is nothing other than speculative, unsupported claims that form the basis for beliefs that have been shown to be untrue that supports these witnesses' rate design proposals. They should be rejected.

OKLAHOMA ATTORNEY GENERAL

EDWIN C. FARRAR

Responsive Testimony

Edwin C. Farrar submitted pre-filed responsive testimony on behalf of Mike Hunter, Oklahoma Attorney General. He testified as to his educational and professional background, which included his professional licensure as a Certified Public Accountant and his long tenure in regulatory proceedings before the Commission, beginning in 1985.

Mr. Farrar recommended that the Commission take into account three major factors as it considers the application of Empire for a large rate increase. First, Mr. Farrar noted that Empire's most recent rate case in any jurisdiction before the Oklahoma case was in Kansas. Mr. Farrar explained that the Kansas case was actually withdrawn as part of an agreement that would allow Empire to implement a rider to recover amounts related to its environmental compliance investments. Second, Mr. Farrar noted that the magnitude of the increase was significant enough to constitute "rate shock," which would be difficult for many ratepayers to absorb without some form of mitigation plan. Finally, Mr. Farrar noted that the Commission's reliability statistics showed that Empire had the worst reliability of any listed electric utility in Oklahoma, sustaining nearly twice as many outages as the average electric utility located within the state.

Mr. Farrar recommended that, in light of the three major factors above, the Commission should only allow recovery for environmental investments through an environmental compliance rider, if it approves a rate increase at all. Mr. Farrar reviewed salient features of the environmental compliance rider used in Kansas, including recovery of depreciation and a return on the investments. The Kansas rider also included a delay of any rate case that effectively would require a test year under Liberty Utilities, Inc. ownership. Mr. Farrar provided suggested calculations for the environmental compliance rider that amounted to $866,968 in annual revenue, which would be a $0.005561 kWh surcharge if allocated on a flat kWh basis.

Mr. Farrar also recommended that, if the Commission were to follow Empire's plan to substantially increase base rates, it should follow the same methodology approved in other recent rate cases to address revenue requirement issues.

Rate Design

Mr. Farrar also submitted pre-filed responsive testimony on rate design issues. Mr. Farrar explained that the initial rate design plan of Empire resulted in a 55.00 percent increase in base rates for residential customers, which he argued constituted rate shock. He testified that his prior recommendation to implement an environmental compliance rider would alleviate this rate shock by reducing the total rate increase.

Mr. Farrar also recommended that, if the Commission chooses to instead follow Empire's proposed plan to substantially increase rates, it should forgo any move to equalized relative rates of return in this case. As he explained, Empire's proposed rate design plan would move all customer classes closer to equalized rates of return, which explains the larger percentage increase for residential customers at 55.00 percent. He testified that an important method for mitigating rate shock in this case would be to delay any move to equalized rates of return, instead allocating any rate increase equally across customer classes.

Lastly, Mr. Farrar recommended that the Commission deny Empire's request to increase its customer charge. He explained that Empire had requested an increase in residential customer charges from $12.50 to $20.59 for standard electric customers and an increase from $12.50 monthly to $25 monthly for total electric customers. Mr. Farrar noted that the residential customer charge in Empire's other jurisdictions was much closer to the Company's current customer charge, amount to $13.00 monthly in Missouri and $14.00 monthly in Kansas.

Rebuttal Testimony

Mr. Farrar also submitted pre-filed rebuttal testimony. Mr. Farrar evaluated various adjustments recommended by PUD and OIEC in light of his earlier recommendation that the Commission use the same methodology as in its other recent rate cases, if it chooses to follow the proposed plan to substantially increase base rates rather than implementing an environmental compliance rider.

First, Mr. Farrar noted that PUD had corrected a mistake in the income tax calculations of Empire that overstated the Company's revenue requirement by approximately $580,000, based on Empire's original rate model. Empire had not implemented a fully normalized tax calculation by, essentially, adding the deferred income tax value instead of subtracting it.

Next, Mr. Farrar recommended that the Commission reject a return on equity set at 9.90 percent, as proposed by PUD. He provided four reasons for this position. First, he explained that 9.90 percent was higher than in other recent rate cases, without evidentiary support. Second, he explained that the evidence in the record actually supported a much lower return on equity, including the analysis provided by PUD's own witness. Third, he noted that the most recent return on equity used in Kansas was 9.30 percent. Fourth, he testified that Empire's persistent record of poor reliability counseled in favor of a reduced Return on Equity.

Mr. Farrar then recommended that, if the Commission sets new higher base rates, Accumulated Deferred Income Taxes should be updated to December 31, 2016, using six-month update data. He explained that OIEC had properly made this update but that PUD had not done so. Mr. Farrar noted this adjustment would incrementally reduce rate base by $688,863, which was later corrected to $688,836.

Mr. Farrar recommended that, if the Commission sets new higher base rates, the Commission should adopt the depreciation rates proposed in OIEC's depreciation study, which were more credible than the rates proposed by Empire. He explained that Empire's depreciation study assumed future additions and retirements of plant that were not complete during the test year. He noted that in its other most recent rate cases, the Commission had adopted the best depreciation studies in the record, which included studies by the same witness who prepared OIEC's depreciation study in this case. Adopting OIEC's proposed depreciation rates would result in a reduction to the revenue requirement of $439,856.

Mr. Farrar next recommended that, if the Commission sets new higher base rates, the Commission should adopt an adjustment proposed by OIEC to remove future hiring and future raises from Empire's payroll expenses. He explained that those changes would occur outside the test year and that no such expenses had been approved by the Commission in its most recent rate cases. This adjustment would result in a $55,869 reduction from the revenue requirement.

Next, Mr. Farrar addressed whether the Commission should disallow either half or all of Empire's short-term incentive compensation. Mr. Farrar noted that PUD had recommended disallowance of half in light of past Commission practice, while OIEC had recommended disallowance of all short-term incentive compensation based on Empire's poor reliability track record. Mr. Farrar opined that the Commission should take into account Empire's poor reliability track record in other ways—such as Return on Equity—before considering it in the context of short-term incentive compensation, favoring disallowance of half. The adjustment to remove half would reduce the revenue requirement by $22,733, while removing all short-term incentive compensation would reduce the revenue requirement by $45,465.

Mr. Farrar also recommended that, if the Commission sets new higher base rates, it should disallow all long-term incentive compensation and supplemental executive retirement plan expenses, rather than following PUD's recommendation to disallow only 75 percent of long-term incentive compensation. Disallowance of all long-term incentive compensation was the approach the Commission had followed in its two most recent rate cases PUD's recommendation. The disallowance of all long-term incentive compensation would reduce the revenue requirement by $37,094, while disallowance of supplemental executive retirement plan expenses would reduce the revenue requirement by $2,034.

Mr. Farrar recommended approval of PUD's phase-in proposal to mitigate rate shock if the Commission chooses to set new, higher base rates. He noted that he instead recommended implementation of an environmental compliance rider and no increase in base rates.

Lastly, Mr. Farrar also addressed OIEC's differing allocation method for its environmental compliance rider. Mr. Farrar had allocated the rider across all customer classes on a per-kWh basis, while OIEC had allocated it on an equal percentage basis using existing shares of revenue. Mr. Farrar testified that his proposal better matched the rider approved in Kansas and would be simpler to calculate, but he did not object to OIEC's position.

<u>Hearing Testimony</u>

At the hearing on the merits, Mr. Farrar made minor corrections to correct errors in his pre-filed rebuttal testimony.

On cross-examination, Mr. Farrar stated that the 9.30 percent return on equity used by the Kansas Corporation Commission to calculate Empire's environmental compliance rider was not applied to the entirety of Empire's rates in Kansas.

Mr. Farrar also agreed that it could be reasonable to include ad valorem taxes in an environmental compliance rider. He also stated that he thought it likely that future investments would be required to keep Empire's generating units operating, although he explained that such a likelihood did not support estimating future investments to set depreciation rates. He also stated that he did not provide a recommendation on how to reduce the service lives of Empire's assets.

Lastly, Mr. Farrar agreed that an equal-percentage allocation of revenues from an environmental compliance rider would be reasonable.

On redirect examination, Mr. Farrar stated that Empire's witness Thomas J. Sullivan also did not provide any recommendation on the reduced service lives of Empire's assets. He also explained that a per-kWh allocation was used for the environmental compliance rider in Kansas and would be simpler to calculate and understand.

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

MARK E. GARRETT

Revenue Requirement

Responsive Testimony

Mr. Mark E. Garrett is the President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation and consulting services. He is an attorney and CPA with more than 25 years of experience testifying as an expert witness in gas and electric utility rate cases. He appeared in these proceedings on behalf of Oklahoma Industrial Energy Consumers ("OIEC"). OIEC represents the interests of industrial companies and other large energy consumers. Electric power costs can constitute a significant percentage of industrial and other large consumers' operating costs. Industries served by Empire operate in competitive business environments and are interested in the Commission setting rates that result in the delivery of reliable power at the lowest reasonable cost.

A. Empire's proposed increase is unconscionable and constitutes rate shock.

Empire is recommending an approximate $3.8 million increase in Oklahoma. This represents a 45.26% increase in base rates and a 27.58% increase in overall rates. According to the Company, the requested increase is primarily driven by new capital investment to comply with Environmental Protection Agency ("EPA") air quality regulations at its Asbury and Riverton 12 plants.

Empire's last rate case was Cause No. PUD 201100082. Since its last rate case in 2011, Empire has been investing large amounts in new rate base with no notice to the Commission or to the Company's customers. It is irresponsible for a utility to incur such costs for five years before informing its customers that it intends to nearly double their base rates. Empire's requested base rate increase of 45.26% increase is unconscionable. Generally, a base rate increase of even 10% would constitute rate shock. Empire has proposed an increase here nearly five times as large. A 27.58% increase in overall rates over a 5-year period is also unreasonable. This amounts to an average annual increase of 5.5%. In comparison, the Consumer Price Index ("CPI") rose by an annual average increase of 1.32% over the period 2012 to 2016. Empire's requested increase is more than 4 times the CPI average.

B. Empire's rate increase in Oklahoma should be in line with its Kansas Settlement.

Empire's requested increase is *inequitable* compared to its last Kansas rate case. Last year Empire sought a similar rate increase (25.64%) in Kansas, a jurisdiction like Oklahoma, in which Empire had not filed a rate case since 2011. The increase in Kansas was driven by the same two factors: the Asbury and Riverton 12 environmental costs; and Empire's failure to timely file rate cases. However in Kansas, Empire withdrew its rate case and settled for a much more reasonable increase.

Pursuant to a Unanimous Settlement Agreement in Docket No. 16-EPDE-410-ACQ ("410 Docket") involving Empire's application for approval of a merger with Liberty Utilities (Central) Co., the Kansas Corporation Commission ("KCC") authorized the following: (1) Empire's withdrawal of the Kansas rate case, (2) a moratorium on another rate case filing until May 1, 2018, (3) collection of the Asbury and Riverton 12 capital costs through an environmental compliance rider, subject to refund and annual true-up. The settlement reached in Kansas, and approved by the KCC, was that Empire would recover its Asbury and Riverton 12 capital cost increases, and nothing more.

By its agreement to the Kansas settlement, Empire has indicated that these terms would result in *just and reasonable* rates. The KCC in the 410 Docket also determined that the Kansas settlement terms resulted in *just and reasonable* rates. In my view, before this Commission considers Empire's requested increase, the Company should address the appropriateness of asking that Oklahoma ratepayers incur significantly higher rate increases than the rate increases received by Kansas ratepayers.

It is appropriate to consider the Kansas settlement purposes of showing the utility agreed to terms it found *just and reasonable*. Moreover, the Kansas settlement is particularly relevant to this case because of its close proximity in time and similarity of jurisdictional impact. In other words, Empire's Oklahoma ratepayers comprise an even smaller jurisdictional percentage of its overall service territory than its Kansas ratepayers do. Thus, the impact of implementing the same terms in Oklahoma as in the Kansas settlement will have no greater financial impact on Empire. The converse, however, is not true. If the Commission were to approve Empire's requested rate increase, the Oklahoma ratepayers in Empire's service territory would suffer tremendous detrimental financial impact.

Mr. Garett recommended that the Commission establish rates in this case based on the same terms in the Kansas settlement. The Commission should authorize a rider for Empire's collection of the capital costs of the Asbury and Riverton 12 projects, subject to refund and subject to a Commission review for prudence of these investments in Empire's next Oklahoma rate case.

The Net Plant in Service for the Asbury and Riverton 12 additions, after deductions for accumulated depreciation and ADIT, is $233,325,825. The Oklahoma jurisdictional amount of Net Plant in Service is $6,421,127. Assuming a pre-tax rate of return of 9.79%, which is OIEC's recommended rate of return, the annual return and depreciation expense on the Asbury and Riverton 12 net plant balances would be $804,205. These costs should be distributed to the rate classes based on the current revenues in each class and collected then on a kWh basis.

C. Traditional ratemaking requires significant adjustments and disallowances.

In his testimony, Mr. Garrett discussed the inequities and insufficiencies in Empire's application that lead him to strongly recommend the Commission adopt the Kansas settlement approach. However, if the Commission decides to take another approach, numerous adjustments and disallowances are required to reduce Empire's proposed rate increase.

1. <u>6-Month Rate Base Updates</u>. 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. As a result of this requirement, Mr. Garrett made following adjustments to update rate base balances to December 31, 2016:

OIEC Adjustment to Actual Balance at 12/31/2016		OK Jurisdictional Amount
Plant in Service		$99,489
Accumulated Depreciation		$(134,465)
Accumulated Deferred Income Tax		$(73,619)
Customer Deposits		$(250)
Prepayments		$2,352
Materials & Supplies		$(4,162)

2. <u>Annual Incentive Compensation Expense Adjustment</u>. Mr. Garrett proposed that the Commission exclude 100% of the annual incentive plan expense. This treatment removes all of the incentive-plan costs associated with financial performance measures, because incentive plan costs associated with financial performance are traditionally removed from rates. It also removes all of the incentive-plan costs associated with customer satisfaction and reliability, because Empire has performed so poorly in these areas over the past several years. The adjustment to remove 100% of Empire's annual plan expense and applicable payroll taxes is $49,048.

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

1) Payment is uncertain;
2) Some factors affecting earnings are not in the control of employees;
3) Earnings-based incentive plans can discourage conservation;
4) The utility assumes no risk associated with incentive payments;
5) Financial incentives should be paid out of increased earnings;
6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.

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

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

The argument that incentives should be included in rates because the amount is reasonable when compared with amounts paid by other utilities misses the point. The question for regulators is not whether the amount paid for incentives is reasonable, but whether the incentives are necessary for the provision of service. The utility is free to offer whatever compensation package it wants to offer, but most commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings.

Although Empire's plan includes operational factors, Mr. Garrett recommended that all of the costs associated with Empire's operational measures such as safety, reliability and customer satisfaction should be disallowed because the Company has performed poorly in these areas in recent years. Empire's JD Power Customer Satisfaction ratings were far below average in 2016. The Company's Reliability Scorecard filed annually with the Commission was also poor in 2016. In fact, Empire's SAIFI scores were the worst in the state. On average, Empire's customers experienced 2.5 outages per customer in 2015. This was 2½ times the state average.

In his testimony, he referenced several examples in which this Commission has denied recovery of incentive compensation. For instance, in PUD 91-1190, at page 145, this Commission disallowed the entire cost of both ONG's plans, finding that the incentive plans were designed to increase corporate earnings. In PUD 04-610, the Commission ordered the disallowance of the entire cost of ONG's incentive compensation payments. In OG&E's 2005 rate case, PUD 200500151, the Commission's final order disallowed 60% of the Company's Teamshare expense.

3. Long-Term Stock Incentive Plan Adjustment. The Company is proposing to include $37,574 in rates for its long-term incentive plan for officers, directors and selected senior management of the Company. Long-term incentive compensation payments to officers, executives and key employees are generally excluded for ratemaking purposes. Since officers of any corporation have a duty of loyalty to the corporation and not to the customers, these individuals typically put the interests of the company first. The interests of the company and its customers are not always the same, and at times, can be quite divergent. Since compensation is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of

employee and shareholder interests means the costs of these plans should be borne solely by the shareholders.

On a number of occasions this Commission has addressed the issue of whether to include long-term incentive compensation in rates. The Commission excluded the entire amount of long-term incentive compensation in Cause Nos. PUD 910001190; PUD 200400610; PUD 200600285; PUD 200800144; and PUD 201500208.

Garrett Group, LLC's Incentive Compensation Survey, discussed in the previous section of this testimony, also shows that most states disallow recovery of long-term incentives. In keeping with Oklahoma's long-standing regulatory treatment of this issue, he recommended an adjustment to remove 100% of Empire's long-term incentives payroll taxes of $37,574.

4. Supplemental Employee Retirement Plan (SERP) Adjustment. The Company provides supplemental retirement plan benefits to certain highly-compensated employees. These supplemental retirement plans for highly compensated individuals are provided because benefits under the general retirement plans are subject to limitations under the Internal Revenue Code. Benefits payable under these 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 $265,000 for 2016.

He recommended that SERP costs be disallowed as a matter of principle. If SERP costs are disallowed, ratepayers will pay for all of the executive benefits included in the Company's regular pension plans, and shareholders will 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.

The Oklahoma Commission has disallowed 100% of SERP expense in Cause Nos. PUD 200600285; PUD 200800144; and PUD 201500208. Similarly, the Texas commission disallowed Entergy's SERP costs in Docket No. 39896. The Nevada commission disallowed NVE's SERP costs in Docket Nos. 01-10001, 03-10001, 06-11022, 08-12002, and 11-06006. The Arkansas commission disallowed SERP costs in Entergy Arkansas's last litigated rate case in that state, Docket No. 13-028-U. SERP costs are excluded in numerous other states as well.

Because officers of any corporation have a duty of loyalty to the corporation, these individuals are required to put the interests of the company first. This creates a situation where not every cost associated with executive compensation should be passed on to ratepayers. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs are more appropriately borne by shareholders. The impact of disallowing 100% of SERP cost in this docket is $(2,061).

5. Payroll Expense 6-Month Update. Empire made two adjustments to increase its annualized payroll expense levels for future pay raises and unfilled positions. Empire provided no testimony to support these adjustments. Typically, unsupported pay increases after the test period are inappropriate. Unfilled positions do not represent actual expenditures of the utility and thus, should not be included in rates. Mr. Garrett proposed to reverse these improper

adjustments, resulting in an Oklahoma jurisdictional adjustments of a $72,205 decrease to payroll expense, and a related $4,693 decrease for payroll tax.

6. Revenue 6-Month Update. In response to AG 3-3, Empire provided revenues updated for customer growth through December 31, 2016. The adjustment for updated revenues is $78,817.

7. Depreciation Adjustment. OIEC witness David Garrett proposed adjustments to the Company's depreciation study resulting in new proposed depreciation rates for many of the Company's plant accounts. The impact of his adjustments on the revenue requirement of Empire is a reduction in depreciation expense of $(439,856).

8. Cost of Capital Adjustment. With respect to cost of capital, OIEC witness David Garrett recommends a Return on Equity ("ROE") of 9.0%. The impact of his recommended ROE on the Oklahoma revenue requirement is a reduction of $(396,953).

9. Unsupported Plant Addition Costs. The Company identifies $669.5M of plant additions since the Company's last rate case in Oklahoma, for which Empire seeks cost recovery. Empire provides minimal testimony in support of $304M of these additions. Specifically, Empire provides very limited testimony in support of its environmental upgrades at Asbury and Riverton 12, but provides virtually no testimony in support of the remaining additions in the amount of $365.5M, which is about $10.1M to the Oklahoma jurisdiction.

In every rate case the applicant has the burden of proving the reasonableness of the rates it seeks. Mr. Garrett does not believe that Empire has met its burden with respect to its plant additions. The Commission has not been provided with sufficient evidence to determine whether these plant additions are prudent, or whether the costs are just and reasonable.

Empire has requested an unprecedented 45.26% increase in base rates with virtually no support for the majority of its asset additions, and with very minimal support for Asbury and Riverton 12 additions. The Commission would be justified in rejecting Empire's entire requested rate increase based on the fact that Empire failed to provide adequate support for the asset additions it claims are causing the increase.

Mr. Garrett recommended that, at a minimum, the Commission should reject all of the requested increase related to the $365.5 million of unsupported plant, along with all of the costs associated with that plant, such as depreciation, property tax, O&M expenses and administrative costs, with a finding that the Company would be eligible to resubmit these costs for consideration in rates in the Company's next rate case proceeding.

D. Conclusion

In the conclusion of his revenue requirement testimony Mr. Garrett recommended that the Commission authorize an environmental compliance rider for Empire's recovery of the capital costs of the two environmental compliance projects, Asbury and Riverton 12, similar to what was authorized in Kansas by the Kansas Corporation Commission, but nothing more. This is a more equitable treatment and would mitigate the rate shock that Oklahoma ratepayers would otherwise experience as result of Empire's irresponsible handling of regulatory matters in Oklahoma.

Based upon the insufficiencies in Empire's filing, he does not recommend that the Commission adopt a traditional approach in this rate case. If the Commission decides to follow a traditional ratemaking approach, it should adopt all of the adjustments outlined in his testimony, including an adjustment to reject recovery in this proceeding of the unsupported plant, and costs associated with that plant, such as depreciation, property tax, O&M expenses and administrative costs.

Rate Design

A. ECP Rider Cost Recovery and Allocation Recommendations

In Mr. Garrett's revenue requirement testimony, he recommended that the Environmental Compliance Plan ("ECP") rider be approved by this Commission. The cost of that rider should be allocated on an equal percentage basis to all customer classes. This allocation method ensures that all customers share equally in these additional environmental compliance costs.

B. Alternative Class Cost of Service and Rate Design Recommendations

If the Commission does not accept the recommendation in Mr. Garrett's Revenue Requirement testimony to implement an ECP rider with no other rate changes, and instead implements on some other basis, the Commission should make two modifications to the Company's cost of service study:

1. Transmission Plant Allocation. Empire's class cost of service study should be modified to utilize the 4 Coincident Peak ("4CP") methodology for allocation of its transmission costs, rather than Empire's proposed 12 Coincident Peak ("12CP") methodology. A 4CP methodology reflects how the transmission system is actually used in Oklahoma. It is also the methodology approved by this Commission regarding allocation of transmission costs for both OG&E and PSO.

2. Production Plant Allocation. Empire's class cost of service study should be modified to utilize the 4 Coincident Peak Average and Excess ("4CP AED") methodology for allocation of its production costs, rather than Empire's proposed 12 Coincident Peak Average and Excess ("12CP AED") methodology. A 4CP AED methodology reflects how Empire's production plant is actually used in Oklahoma. It is also the methodology approved by this Commission regarding allocation of production costs for both OG&E and PSO.

Rebuttal Testimony

Mr. Garrett testified that Empire identified $669.5M of plant additions, but only supported $304M of these additions. Specifically, Empire provided limited testimony to support its environmental upgrades at Asbury and Riverton 12, but provided no testimony to support the remaining additions in the amount of $365.5M. As a result, the Commission has not been provided with sufficient evidence to determine that the plant additions were prudent investments. He testified that Empire has the burden of proving the reasonableness of the rates it seeks, and that Empire has not met its burden with respect to recovery of the unsupported Plant additions. Finally, he testified that the Commission should reject all of the requested increase related to the $365.5 million of unsupported plant, and allow the Company to resubmit these costs for inclusion in rates in the Company's next rate case proceeding. In his rebuttal testimony, he addressed the responsive testimony filed by Staff and the Attorney General in this proceeding.

A. Rebuttal to Staff's Recommendations

1. Lack of Evidence for Plant Additions. Staff did not address the fact that Empire provided no evidence to support the prudence of its plant additions. Instead, Staff included all of the plant in the Company's proforma rate base in its recommended revenue requirement, despite Empire's failure to show that the new plant additions were prudent or that the costs were just and reasonable.

2. Rate treatment for Empire in Kansas and Arkansas jurisdictions. Staff's recommendations for Oklahoma ratepayers are not consistent with the ratemaking treatment Empire received in Kansas or Arkansas.

In Kansas, Empire requested a comparable increase (25.64%) last year, a jurisdiction in which, like Oklahoma, Empire had not filed a rate case since 2011. The increase in Kansas was driven by the same two factors as in Oklahoma: the large increase for the Asbury and Riverton 12 environmental costs; and Empire's failure to timely file rate cases. In Kansas, however, Empire withdrew that rate case, and pursuant to a Settlement Agreement, Empire agreed to the following terms: (1) Empire's withdrawal of its Kansas rate case, (2) a moratorium on another rate case filing until May 1, 2018, and (3) collection of the Asbury and Riverton 12 capital costs through an environmental compliance rider, subject to refund and an annual true-up. Staff acknowledged the rate treatment approved for ratepayers in Empire's Kansas jurisdiction but did not recommend such treatment for Oklahoma ratepayers.

Staff failed to consider the rate treatment received by Empire's ratepayers in Arkansas. In Arkansas, ratepayers are receiving virtually the same rate treatment ratepayers in Kansas are receiving. Arkansas ratepayers are paying for the Asbury and Riverton 12 environmental compliance costs through an Environmental Compliance Cost Recovery (ECP) rider, and Empire has a rate case stay-out provision effectively through 2018. Empire is required to have 12 months of post-merger actual accounting data before it files its notice of intent for its next rate case. The merger became effective at the end of January 2017, which means Empire cannot file its notice of a rate case until early 2018. With a 60-day notice period and a 10-month processing period for rate cases in Arkansas, Arkansas ratepayers will not see a rate change until early 2019. This provides ratepayers with two years of rate stability after the merger.

Mr. Garrett testified that to be constitutionally valid, utility rates must be *just, reasonable* and *non-discriminatory*. In his opinion, the Oklahoma Commission should protect Oklahoma ratepayers by affording them the similar treatment that was afforded to Kansas and Arkansas ratepayers under similar circumstances.

Based on Empire's rate treatment in Kansas and Arkansas, which effectively requires a 2-year rate stabilization plan after the Liberty-Empire merger, a similar rate-freeze period is appropriate for Oklahoma. He recommended that the Commission require that Empire provide to the Commission at least twelve months of actual post-merger accounting data to include in its next rate case application, so that the historical test year in Empire's next rate case application is a 12-month period that includes all post-merger cost data. This will result in rate treatment in Oklahoma that is consistent with the rate treatment in both Kansas and Arkansas.

3. Staff's overstated 9.9% ROE. Staff does not explain why it is recommending a 9.9% ROE for Empire when the Commission in two recent litigated rate cases awarded 9.5% returns to both OG&E and PSO. Staff failed to distinguish Empire in any way that would justify the higher rate of return. Since the top end of Staff's range for Empire is 8.0%, it cannot show a financial basis for its higher recommended return. Moreover, from an operational standpoint, Empire's allowed return should be much lower than the returns of OG&E and PSO, because Empire's quality of service and reliability are so much lower. Mr. Garrett testified that awarding Empire a higher return is tantamount to rewarding the Company for poor operational performance. He recommended instead that the Commission award an ROE of 9.0% consistent with the recommendation of OIEC witness David Garrett.

4. Staff's treatment of Long-Term Incentive Compensation. Staff recommended a disallowance of only 75% of Empire's long-term incentive compensation. Mr. Garrett testified that this recommendation is misguided for all of the reasons he included in his responsive testimony. This Commission has consistently excluded the stock-based incentives for electric utilities. In fact, this Commission recently deliberated this issue in OG&E's and PSO's recently-concluded rate cases, Cause No. PUD 201500273 and Cause No. PUD 201500208. In the Final Orders in these causes, the Commission decided that 100% of long-term incentive compensation should be excluded from rates.

B. Rebuttal to the Attorney General's Recommendations

1. The Attorney General's Energy Allocation. The Attorney General, like OIEC, recommended that Empire should be allowed to recover only the capital costs associated with Asbury and Riverton 12 environmental compliance upgrades through a rider mechanism. However, the Attorney General recommended that these costs be allocated to and collected from the customers on an energy (kWh) basis, which is not a cost-based allocation.

Mr. Garrett testified that since the Asbury and Riverton 12 capital costs are production plant costs, they should be allocated using a production plant allocator. In Oklahoma, capital costs associated with production assets have always been allocated on a demand basis, not on an energy basis, and this is the appropriate allocation of these costs.

An energy based allocation of these costs would create a significant subsidy to the residential class from the industrial classes. In essence, it would unfairly penalize the high load factor commercial and industrial customers. Since the residential class already has a significant subsidy that needs to be reduced, not increased, the AG's recommendation should not be accepted.

Surrebuttal Testimony

A. Mark Garrett Surrebuttal Testimony (from Transcript of May 11, 2017, Vol. I, Morning Session, beginning on page 82)

Mr. Garrett's testimonies were admitted. (5/11/17 a.m. Tr. at 82-83). His surrebuttal issues list provided on April 17, 2017, was also admitted. *Id.* at 83-84. Mr. Garrett prepared a surrebuttal exhibit, MG-2, alternate proposal, Hearing Exhibit 40. *Id.* at 84-85. It is the revenue requirement calculations, similar to the one he provided with his responsive testimony, but it is updated to include all of the six-month plant and other rate base updates provided by PUD that the Company and PUD agreed upon, as does OIEC; they are all working with the same numbers. *Id.* at 84-85. It has also been updated to quantify the impact of the $369 million of unsupported plant expense, i.e., the plant that is not environmental compliance related. *Id.* at 85. It quantifies those adjustments on Lines 15 through 21, and it includes amounts on lines 48, 49, and 50 for depreciation and property tax on O&M and administrative general expenses related to those assets. *Id.* On Lines 32 through 40, it takes out the adjustments that the Company has agreed to, and leaves in the adjustments that the Company has not agreed to. *Id.* Line 1 starts with the Company's revised position. *Id.* That number should tie to the revenue requirement that you find in Staff's accounting exhibit for the Company's position. *Id.* It is an alternative proposal. *Id.* at 86. OIEC's primary proposal is the environmental compliance plan rider, so that the Company would be allowed to collect Asbury and Riverton 12 costs until such time as they can file a rate case with proper support for these additional assets that were unsupported in this case. Ex. 140 is an alternate position if the Commission does not approve the rider; it shows the adjustments that would need to be made. *Id.* It also quantified the value of the unsupported plant additions. *Id.* Mr. Garrett testified that one additional correction needs to be made. Line 11, accumulated for income tax, still has Mr. Garrett's adjustment because he thought the Company had not corrected its accumulated deferred income tax. *Id.* However, Mr. Garrett saw an exhibit at trial where the Company has corrected the accumulated deferred income tax, so that the line item would come out. It would add $73,000 to the bottom line. *Id.* at 86-87.

Once the correction is made, Mr. Garrett's traditional rate case approach results in a rate increase to the Company of a little under $600,000. *Id.* at 87-88. OIEC is not suggesting that any of the plant is disallowed. *Id.* at 88. OIEC is saying it is not deemed used and useful at this point until it is properly supported in the next rate proceeding. *Id.* at 88. Then it will come into rate base as used and useful plant. *Id.* The specifics about the unsupported plant adjustments are on Ex. 140 at Lines 15 through 21 and 48 through 50. *Id.*

Mr. Garrett testified that Mr. Krygier gave three reasons to reject the Kansas Plan, which are that it would be kicking the can down the road; it would be cherry-picking; and it would be single-issue ratemaking. *Id.* at 89. Mr. Garrett testified that it would be putting off some of these increases for later. *Id.* That is what the Company agreed to in Kansas and Arkansas. *Id.* Also, it is important in this case that so much of the rate request is new rate base that had no testimony at all as to why it was needed or why it was added, or if the costs were prudent. *Id.* at 89. For the used and useful determination, there has to be testimony supporting that request. *Id.* Mr. Garrett testified that it is important that the Commission not set a standard where a company can get a rate increase with no support for most of the assets that are going into the rate base. *Id.* at 89-90.

Mr. Garrett testified that OIEC is not cherry-picking, but is relying on the results in both Kansas and Arkansas. *Id.* at 90. Further, without the support for these other assets, we are left with either a $600,000 a year rate increase, or we have offered $800-$900,000 rate increase to cover the environmental compliance costs. *Id.*

Mr. Garrett testified that he agrees that the rider is single-issue ratemaking. *Id.* at 90. Mr. Garrett testified that this has disadvantages, but it is all we are left with. *Id.* It is consistent with the statute that allows a rider for environmental compliance costs. *Id.* It is temporary until the Company files its next rate case. *Id.* at 90-91.

Mr. Garrett testified, with regard to Mr. Lyons' rebuttal testimony regarding delaying a rate increase, that OIEC is not suggesting that there be a delay for all costs. *Id.* at 91. OIEC is suggesting that the Company recover its an environmental compliance costs now because they supported those, and that we delay the rest until they bring in proper support for those assets as well. *Id.*

Mr. Lyons says the Company believes its payroll expense and aggregate are necessary to attract and retain qualified employees. Mr. Garrett testified that Mr. Lyon's argument has been raised at the Commission for 25 years and it has been rejected in all the cases. *Id.* at 92. Financial based incentives are not allowed. *Id.* Mr. Garrett testified that this case is rare, but the rest of the incentives that aren't financial are related to reliability and customer satisfaction. *Id.* The Company is doing a really poor job in those areas right now. *Id.* Poor performance should not be rewarded, and that is what the incentives are doing. *Id.* at 92. If they improve, the incentives could be included in rates at that time. *Id.*

OIEC omitted vacant positions from the payroll adjustment because those are not employees of the Company. *Id.* at 92. They are just vacant positions. *Id.* The Commission has addressed this issue a couple of times before when OG&E asked for vacant positions and they were not allowed. *Id.* at 92-93. Mr. Lyons admitted that the 27 has grown to 30, so the vacant positions are getting bigger, not smaller. *Id.* t 93.

With respect to Plant additions, Mr. Garrett testified that there was no direct testimony provided as to what the additions were and why they were needed. That is a requirement in every rate case for a new plant. *Id.* at 94.

Mr. Garrett testified that he agrees that rate case expenses are necessary and should be included, in an appropriate and proper amount. *Id.* at 95. Tying recovery of rate case expense to the success of the utility in the final order would be a way of sharing those costs with the Company so that they don't all fall on ratepayers. *Id.*

Mr. Garrett testified that witness Mertens said that the testimony of Mark Garrett and Edwin Farrar suggest that Empire's performance in other states has a higher reliability than Oklahoma. That was not Mr. Garrett's testimony. Mr. Garrett's testimony compared Empire's reliability performance with other utilities in Oklahoma. *Id.* at 95-96. Mr. Garrett used the reliability report to show that we should not be paying incentives for reliability because you do not reward poor performance. *Id.* at 96.

Mr. Garrett's surrebuttal regarding Mr. Mertens' testimony about plant additions is the same as his surrebuttal to Mr. Lyons. The additions, other than environmental compliance, were not supported. *Id.* at 96.

In response to witness Schwartz, Mr. Garrett testified that the reliability report that OIEC used was the correct report. *Id.* at 96-97. It was a complete report. *Id.* at 97.

As for incentive comparison, i.e., incentives that were paid in 2016, it needs to be based upon actual data at the time and not what we hope the Company will do in the future. *Id.* at 97. The ratepayers should be charged for actual performance of the Company. The J.D. Powers report measures customer satisfaction. The Company is at the bottom of both reports. *Id.*

B. <u>Mark Garrett Surrebuttal Testimony (from Transcript of May 12, 2017, beginning on page 72)</u>

Mr. Garrett testified that in his Rebuttal Testimony, Mr. Overcast talks about the differences he has with Mr. Garrett in the allocation of transmission plant and generation plant, where Mr. Garrett recommends a 4 CP for both and Mr. Overcast recommends a 12 CP. (5/12/17 Tr. at 72-73). Mr. Overcast's statement that Mr. Garrett relies on Commission precedent for other utilities in developing his cost of service allocation recommendations is partially right. *Id.* at 73. The Commission has consistently authorized a 4 CP for production costs for PSO and OG&E. *Id.* But that is not all he relied on. *Id.* Mr. Garrett also looked at the peak load each month and developed a little different 4 CP because Empire has a winter peaking system and a summer peaking system. *Id.* Mr. Garrett testified that he used two summer months and two winter months. *Id.*

In response to Mr. Overcast's testimony that it was incorrect for Mr. Garrett to only consider peak load, Mr. Garrett testified that the Commission has always relied on peak load. *Id.* at 73-74. Mr. Overcast wants to take peak load and then layer on other things, like forced outages and scheduled maintenances. *Id.* at 74. You will always have scheduled maintenance. That just waters down the peaks to make them all come out to a 12-peak system. *Id.* FERC allocations are for something totally different than retail so the FERC standards do not apply to retail allocation. *Id.*

Mr. Garrett testified that Mr. Overcast's testimony that Mr. Garret's argument for a 4 CP allocation factor for transmission plant does not reflect cost causation is wrong. The whole point in looking at the peaks is to reflect why the system was built and how it was built. *Id.* at 76. Mr. Overcast says that Empire's transmission costs are allocated to the Oklahoma jurisdiction on a 12 CP basis. *Id.* That is a jurisdictional allocation; it has nothing to do with how you allocate to the retail classes. *Id.* For example, PSO allocates jurisdictionally with a 12 CP, but allocates in Oklahoma with a 4 CP. *Id.* This is important especially for the large customers, the industrial customers because they compete with the surrounding states for market share. *Id.* at 76-77. It puts Empire customers at a huge disadvantage if you have surrounding states and other companies in Oklahoma using a 4 CP and Empire allocates with a 12 CP.

Mr. Garrett testified that Mr. Schwartz's Responsive Testimony, p. 13, figure 3, is PUD's proposed revenue distribution. *Id.* at 80. It is the rate design piece after we do cost of service allocations. This is how the revenue is going to be spread to the classes. *Id.* If we really go to cost of service, it is going to put too much costs on the residential class. *Id.* at 80. When you look at the relative rate of return basis, this class is almost at 1.9, so the return on that class is almost double what it should be. *Id.* at 80-81. The transmission class is fine. *Id.* at 81. Commercial is close. *Id.* All the rest of the classes are getting towards cost of service. *Id.* The GP class is not close enough. Mr. Garrett suggests that the Commission set a band width of 1.25 to 0.75 and that everyone moves into that band. *Id.* Mr. Garrett testified that his band width recommendation would apply to Staff's recommended revenue requirement and to that recommended by OIEC. *Id.* at 82.

Mr. Garrett testified that his revenue distribution recommendation applied to the traditional rate-case approach. *Id.* at 82-83. If the Commission decides instead to go with a rider, the Kansas-Arkansas approach, and just implement the environmental compliance rider, this discussion goes away. *Id.* at 83. Under OIEC's recommendation, if the Commission approves a rider, would spread the costs equally to all classes on an equal percentage. *Id.* at 83.

C. Mark Garrett Redirect (from Transcript of May 12, 2017, beginning on page 112)

Mr. Garrett testified that Hearing Exhibit 140 is a revised version of his Surrebuttal MG-2 alternative proposal. (5/12/17 Tr. at 113). This is the alternative proposal that calculates the revenue requirement based upon OIEC's recommendations that include depreciation, return on equity, and all of the accounting adjustments. Mr. Garrett testified that he changed one number, which affected three different lines. *Id.* He took out the accumulated deferred income tax adjustment on Line 11, which was the OIEC recommendation. *Id.* The Company corrected its accumulated deferred income tax number in its revised exhibits, so the adjustment is no longer needed. *Id.* This exhibit represents OIEC's revised accounting exhibit and reflects the recommended rate revenue requirement increase for OIEC's alternative proposal. *Id.* at 114.

DAVID J. GARRETT

Responsive Testimony

David J. Garrett is the managing member of Resolve Utility Consulting, PLLC. On March 13, 2017, Mr. Garrett filed two separate responsive testimony documents on behalf of the OIEC. Part I of his responsive testimony addressed the cost of capital and related issues, and Part II of his responsive testimony included depreciation expense and related issues.

Cost of Capital

In formulating his recommendation, Mr. Garrett conducted a Discounted Cash Flow ("DCF") Model and a Capital Asset Pricing Model ("CAPM") on a proxy group of utility companies to estimate the cost of equity for Empire. Applying reasonable inputs and assumptions to these models reveals that Empire's estimated cost of equity is about 7.5%. Pursuant to the legal and technical standards guiding this issue, the awarded rate of return on equity should be based on, or reflective of the cost of equity of 7.5%. However, these legal standards also provide that the "end result" be fair and reasonable under the circumstances. If the Commission were to award a return on equity reflective of Empire's actual cost of equity of 7.5%, it would be technically correct under the rate base rate of return model, and it would not violate any legal standards. However, if the Commission were to set the awarded return at 7.5%, it would represent an abrupt change in Empire's awarded return, and could increase the Company's market risk. For this reason, Mr. Garrett recommends an awarded return on equity of 9.0%, which is the highest point in a reasonable range of 7.5% - 9.0%. In addition, Mr. Garrett recommends the Commission adopt Empire's proposed capital structure consisting of 50.32% debt and 49.68% equity. Mr. Garrett's overall weighted average cost of capital recommendation is 7.14%.

In responding to Company witness Dr. James H. Vander Weide, Mr. Garrett found that several of Dr. Vander Weide's key assumptions and inputs to the DCF Model and CAPM violate fundamental, widely-accepted tenants in finance and valuation. Specifically, Mr. Garrett identified the following areas of concern in Dr. Vander Weide's testimony:

1. In his DCF Model, Dr. Vander Weide's long-term growth rate applied to Empire exceeds the long-term growth rate for the entire U.S. economy. It is a fundamental concept in finance that, in the long run, a company cannot grow at a faster rate than the aggregate economy in which it operates; this is especially true for a regulated utility with a defined service territory. Thus, the results of Dr. Vander Weide's DCF Model are based on unrealistic assumptions and are not reflective of market conditions.

2. Dr. Vander Weide's estimate for the equity risk premium ("ERP"), the single most important factor in estimating the cost of equity, is significantly higher than the estimates reported by thousands of experts across the country. This is because Dr. Vander Weide has inappropriately considered the arithmetic mean total market returns dating as far back as 1926. It is widely-accepted in the finance community that the current and forward-looking equity risk premium is lower than the historical risk premium (especially when calculated through the arithmetic mean).

3. Dr. Vander Weide's estimates for beta for the proxy companies in the CAPM are significantly higher than the betas reported by institutional financial analysts, and are overstated due to faulty assumptions.

4. Dr. Vander Weide's own risk premium is also unrealistic, as it produces cost of equity results for a utility that exceeds any reasonable estimate of the required return on the market portfolio.

In short, the assumptions employed by Dr. Vander Weide skew the results of his financial models such that they do not reflect the economic realities of the market upon which cost of equity recommendation should be based.

Mr. Garrett also testified that when the awarded return is set significantly above the true cost of equity, it results in an inappropriate and excess transfer of wealth from ratepayers to shareholders beyond that which is required by law. This outflow of funds from Oklahoma's economy would not benefit its businesses or citizens. Instead, Oklahoma businesses, such as OIEC member companies, would be less competitive with businesses in surrounding states, and individual ratepayers will receive inflated costs for basic goods and services, along with higher utility bills.

Depreciation

In his depreciation testimony, Mr. Garrett testified that there are several primary factors driving OIEC's adjustment of $439,856 to Empire's proposed depreciation expense in the Oklahoma jurisdiction. These factors, along with their estimated dollar impact on the final adjustment are as follows: (1) removing proposed terminal net salvage on production plants, removing future, unapproved plant additions from the Company's calculated depreciation rates on the production accounts, and leaving the current lifespan estimates for the production units unchanged – $229,806; (2) proposing different Iowa curve shapes and average lives for various transmission, distribution, and general accounts – $154,303; and (3) amortizing the unrecovered costs of Riverton Units 7, 8, and 9 over the estimated remaining life of Riverton 12 – $55,748. Mr. Garrett testified that according to the Supreme Court, Empire bears the burden to make a convincing showing that its proposed depreciation rates are not excessive, and that Empire has not met that burden regarding several issues related to depreciation.

Regarding Empire's production accounts, Mr. Garrett recommended that any proposed terminal and net salvage be removed due to lack of support by the Company. Mr. Garrett also stated that Company witness Thomas J. Sullivan incorporated unapproved future plant additions in the calculation of his proposed depreciation rates, and that this is not an appropriate way to calculate depreciation rates for production accounts.

Regarding Empire's transmission and distribution accounts, Mr. Garrett testified that he made adjustments to the proposed service lives for several accounts based on mathematically better-fitting Iowa curves.

Regarding Empire's proposed amortization of the Riverton Units 7, 8, and 9, Mr. Garrett testified that the undepreciated balance of $7.5 million for these units should be amortized over the estimated remaining life of the new Riverton 12 plant, because the approval of this plant was part of the same environmental compliance plan that called for the retirement of Riverton Units 7, 8, and 9. Thus, Mr. Garrett proposes that the undepreciated portion of the retired Riverton Units 7, 8, and 9 be amortized over 42 years.

Rebuttal Testimony

Mr. Garrett also filed rebuttal testimony on April 3, 2017, in response to PUD witness Geoffrey Rush's responsive testimony regarding Empire's cost of capital and the awarded return. In his rebuttal testimony, Mr. Garrett stated that he did not disagree with the majority of Mr. Rush's cost of equity analysis, as conducted through the CAPM and DCF Model. Mr. Garrett also agreed with Mr. Rush that Empire's cost of equity is well below 8.0%. However, Mr. Garrett disputed Mr. Rush's decision to accept Empire's requested ROE of 9.9% because this recommendation did not comport with Mr. Rush's analysis.

Surrebuttal Testimony

A. David Garrett Surrebuttal Testimony (from Transcript of May 11, 2017, Vol. II, Afternoon Portion, beginning on page 116)

Mr. Garrett testified that he disagreed with Mr. Sullivan's characterization of his depreciation testimony as "cherry-picking." Mr. Garrett testified that he simply accepted some of Mr. Sullivan's recommendations regarding lifespan and did not accept others, which is done with any witness in any case. (5/11/17 p.m. Tr. at 117-118). It is rare to just adopt or reject all of a company's testimony. *Id.*

Mr. Sullivan testified in his rebuttal testimony regarding interim retirements. Mr. Garrett testified that Mr. Sullivan clarified that the Company did not include any terminal net salvage recovery in this case, and Mr. Garrett does not take issue with this. *Id.* at 118. However, Mr. Garrett recommended that recovery of interim retirement should be disallowed due to lack of support. *Id.*

Mr. Garrett testified that Mr. Sullivan's calculation of depreciation rates for production facilities in his rebuttal testimony is unusual. *Id.* at 118-119. The vast majority of depreciation studies do not calculate production rates in this manner because it requires estimating future, unapproved plant additions for many years into the future; in this case more than 50 years for some plants. *Id.* at 119. That is problematic. They should be calculated in the normally-accepted way, which would not include future estimated plant additions and requirements. *Id.* Mr. Garrett testified that the rates he proposed would not include future estimated plant additions and retirements. *Id.*

Mr. Garrett testified that Mr. Sullivan, in his rebuttal testimony, is suggesting that if you do not include interim retirements, you should shorten the life spans of the plants. *Id.* at 119-120. Mr. Garrett testified that where interim rates are excluded, they are excluded without any adjustment to life span. *Id.* at 120.

As far as placement bands, Mr. Garrett testified that he relied on placements that began in 1960, which provided a sufficient amount of time to get an adequate retirement experience to apply Iowa curves to the historical observations. *Id.* Mr. Sullivan included the total banding period, which goes back as far as 1900 for some accounts. *Id.* at 121. As a result, Mr. Sullivan's Iowa Curve that he developed indicate shorter service lives whereas the Iowa Curve that Mr. Garrett developed using the more recent data indicate longer service lives. *Id.* For many accounts and many assets, more recent property tends to last longer. *Id.* Mr. Garrett testified that his data is based on more recent data, but still goes back far enough to give adequate retirement experience. *Id.*

Regarding the issue of cost of capital, Mr. Garrett testified that Dr. Vander Weide used surveys of the average hurdle rate or the average cost of equity in the country. Mr. Garrett testified that it is not instructive to consider the average hurdle rate or average cost of equity because utilities are less risky than the average firm in the market. *Id.* at 122.

Dr. Vander Weide's testimony regarding the assumption that investors' growth expectations are rational is especially problematic. *Id.* at 122-123. By and large, investors do act rationally, and in financial modeling you assume investors act rationally. *Id.* at 123. However, Dr. Vander Weide's testimony seemed to suggest that we also should expect that investors act irrationally and somehow incorporate that into the model. *Id.* Mr. Garrett strongly disagrees with that and has never seen anyone suggest that. *Id.*

Mr. Garrett testified that growth rate is one of the most important issue in this case. It is a fundamental concept of finance that over the long-term, no company can grow its earnings and/or dividends at a greater rate than the growth rate of the aggregate economy in which it operates. *Id.* Therefore, it is concerning that Dr. Vander Weide and others use analysts' growth rates which are short-term growth rates, for the long-term growth rate in the DCF model. *Id.* at 123-124. That is inappropriate. Long-term growth rate should be capped at a reasonable projection of nominal GDP growth, which is what Mr. Garrett did. *Id.* at 124. By using nominal growth GDP, as Mr. Garrett's long-term growth rate for each company in the proxy group, he is suggesting that a regulated utility can match the growth of the entire U.S. economy, which is very optimistic. *Id.* It would be easy to argue that the long-term growth rate of a regulated utility would be less than projected nominal GDP growth, maybe around 3%. *Id.* at 124. Mr. Garrett testified that he is using 4% in his model, in the interest of being conservative and reasonable. *Id.*

Mr. Garrett testified that Dr. Vander Weide suggests that Mr. Garrett did not acknowledge that the CAPM tends to underestimate beta. *Id.* at 124-125. Mr. Garrett agrees that there's some research that suggests that the CAPM can underestimate betas that are less than one. *Id.* at 125. However, the betas published by Value Line and Bloomberg and similar sources account for that by adjusting the raw betas upward. *Id.* They are already adjusted. *Id.* Mr. Garrett testified that the problem with what Dr. Vander Weide did is he took the beta, which was already adjusted higher to account for this research, and then he adjusted even further higher to .9. *Id.* Mr. Garrett cannot recall a utility witness that has done that. *Id.*

In Mr. Garrett's opinion, the Equity Risk Premium in the CAPM mode is the single most important factor in estimating the cost of equity for any company. *Id.* at 125-126. To get to the cost equity estimate, the equity risk premium is probably the most important number, along with the growth rate and the DCF model. *Id.* at 126. Mr. Garrett testified that he did not use the results of his calculation, but actually used a higher equity risk premium result that was published by a respected professor who publishes his Equity Risk Premium results each month. *Id.* He chose the higher result, again, in the interest of being conservative. *Id.* Mr. Garrett testified that he presents his Equity Risk Premium calculation, along with several others, on page 69 of his Testimony, Figure 12. *Id.* The results of this chart were not rebutted. *Id.* at 127.

At page 29, lines 5 to 9, regarding depreciation rates, Dr. Vander Weide misstated that Mr. Garrett said it is best to overestimate depreciation lives. *Id.* Mr. Garrett said that he never said that. *Id.*

PUBLIC UTILITY DIVISION

ROBERT C. THOMPSON

Responsive Testimony

Robert C. Thompson is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as Certified Public Accountant/manager of accounting in the Energy and Water Group. Responsive testimony of Mr. Thompson, was filed on March 13, 2017 in Cause No. PUD 201600468.

Mr. Thompson's testimony addressed recommended 6-month test year ending balances to plant in service, accumulated depreciation and amortization, interest expense in the income tax calculation, income taxes, cash working capital, and the reflection of PUD's recommended rate base and expense adjustments to PUD's Accounting Exhibit.

Mr. Thompson reviewed all information and testimony provided by the Company in this Cause related to the Company's revenue requirement, income taxes, cash working capital. Mr. Thompson further reviewed Commission orders, testimony related to areas in prior causes, and workpapers relating to Empire. Mr. Thompson communicated with the Company through email, phone calls, onsite audits, electronic information/data requests, and reviewed responses to these requests.

Mr. Thompson recommended that based on results of PUD's proposed adjustments and PUD Accounting Exhibit, The Empire District Electric Company should have a base rate revenue increase of $3,036,676. Mr. Thompson further recommended that the base rate revenue increase should be phased-in over a four-year period.

Overall, Mr. Thompson recommended the Commission approve the recommendations included in his testimony and he concluded that the revenue increase is fair, just, and reasonable to both the Company and its ratepayers.

DAVID MELVIN

Rebuttal Testimony

David Melvin is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Senior Public Utility Analyst. Mr. Melvin filed rebuttal testimony on April 3, 2017. The purpose of his rebuttal testimony was to address the responsive testimony filed by Mark E. Garrett on March 13, 2017, specifically section III, E., Unsupported Plant Additions.[5]

Mr. Melvin testified that The Empire District Electric Company ("Company") submitted its Application for an adjustment in its rates and charges for electric service in the State of Oklahoma ("Application") on December 21, 2016. The Company requested the Commission to find that Empire has a total rate revenue deficiency of approximately $3.8 million and to allow the Company to implement tariffs to recover that deficiency, and other relief to which the Commission deems the Company is entitled. Mr. Melvin's rebuttal testimony provided the result of PUD's analysis pertaining to the Company's plant additions and the recommendation that the associated costs are prudent and reasonable.

Mr. Melvin testified that after PUD's review of the Application, associated testimonies, schedules, data requests and responses, statutes and rules, and onsite audits, PUD recommended the Commission accept the adjustments to plant in service requested in the Application, including the six-month post test year recommended adjustment made by PUD witness Robert C. Thompson. Mr. Melvin further testified that he believes the adjustments for plant additions are prudent and the associated costs are reasonable.

TONYA HINEX-FORD

Responsive Testimony

Ms. Tonya Hinex-Ford is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission as an Energy Audit Section Coordinator, in the Energy and Water Group. Ms. Hinex-Ford filed responsive testimony on March 13, 2017, in Cause No. PUD 201600468 The Empire District Electric Company, a Kansas Corporation ("Empire" or "Company"), for an adjustment in its rates and charges for electric service in the State of Oklahoma, for the 12 months ended June 30, 2016.

On December 21, 2016, Empire filed its rate case Application and Supplemental Package requesting an overall increase of approximately $3.8 million, in Oklahoma jurisdictional revenue, which represents an increase of 27.58%. Ms. Hinex-Ford's testimony provided PUD's role, in its review of any company's filing in a rate proceeding, is to be as objective as possible. PUD strives to make recommendations that are fair, just, and reasonable, which should allow the Company to provide safe, reliable service to the ratepayers at a reasonable rate.

[5] Mark E. Garrett Responsive Testimony, page 37, line 10 through page 39, line 20.

Ms. Hinex-Ford testified concerning the list of PUD analysts assigned to the Cause and to the overview of the areas reviewed by PUD. She also testified that PUD's onsite audits allowed PUD to review the actual books, records, and physical plant and equipment utilized by the Company. In addition to the various audits performed, PUD was able to conduct interviews with the operation employees who manage and perform the functions under review. The onsite audits allowed PUD to form a genuine determination of reasonableness rather than to set levels based solely on accounting entries.

Ms. Hinex-Ford reviewed the Application, supporting testimony, workpapers, prior rate cases, relevant statutes, and Commission rules. In addition, Ms. Hinex-Ford issued data requests, reviewed responses, and conducted various onsite audits at the Company's headquarters. After a thorough review of each assigned area, Ms. Hinex-Ford testified that PUD believes that Empire's adjustments in the areas of Insurance Healthcare, along with Injuries and Damages Insurance Expense, are reasonable and in the public interest, and PUD does not have any adjustments to these areas. Ms. Hinex-Ford did not have any recommendation related to the review of the Company's Board of Directors Minutes.

GEOFFREY M. RUSH

Responsive Testimony

Geoffrey M. Rush, witness for the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"), filed Responsive Testimony on March 13, 2017, in Cause No. PUD 201600468. Mr. Rush's testimony was submitted to review items in the December 21, 2016, application of The Empire District Electric Company ("Empire" or the "Company") in Cause No. PUD 201600468. The items he evaluated were:

- The Company's cost of equity
- The Company's cost of debt
- The Company's capital structure
- The Company's weighted average cost of capital
- Payroll expense and incentive compensation
- Pension expense
- Other Post Retirement Welfare Costs

Empire's cost of capital is comprised of two components: debt and equity. While the cost of debt is determined by fixed, contractual interest payments, the cost of equity must be estimated through financial models. Mr. Rush employed three financial models on a group of similar proxy companies to arrive at an estimate of the Company's cost of equity in this Cause, including: 1) the Discounted Cash Flow Model; 2) the Capital Asset Pricing Model; and 3) the Comparable Earnings Model. Finally, Mr. Rush conducted an analysis to determine the Company's optimal capital structure.

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the dividend discount model, which maintains that the value of a security is equal to the present value of the future cash flows that it generates. The general DCF Model may be modified to reflect the assumption that investors receive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation

DCF model, which is what Mr. Rush used in his analysis. All else held constant, the Quarterly Approximation DCF model results in the highest cost of equity estimate for the utility in comparison to other DCF models. The average DCF result for the proxy companies using the Quarterly Approximation DCF model is 7.12%.

The Capital Asset Pricing Model ("CAPM") is a market based model where investors require higher returns for adding additional risk. There are three terms within the CAPM equation that are required to calculate the required return (K): 1) the risk-free rate (R_F); 2) the beta coefficient (β); and 3) the equity risk premium ("ERP") (R_M-R_F), which is the required return on the overall market minus the risk-free rate. The ERP is one of the most important factors in estimating the cost of capital. There are three ways to estimate the ERP: 1) calculating a historical average; 2) taking a survey of experts; and 3) calculating the implied equity risk premium. Mr. Rush incorporated each one of these methods in determining the ERP used in his CAPM analysis. The average CAPM result for the proxy companies is 6.79%.

The Comparable Earnings Model ("CEM") involves averaging the earned returns on equity of other utility companies. In utility rate cases, analysts often perform the CEM on the same proxy group of regulated utilities used in the CAPM and DCF analyses. In conducting the CEM analysis, Mr. Rush averaged the annual earned returns on equity for each of the proxy companies from 2007 to 2016. The composite average and final result of the CEM is 9.82%.

There is a direct relationship between risk and return in that the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. Empire is a smaller company, with fewer customers, and therefore a riskier company than other electric distribution companies that have service territories in Oklahoma. As such, external risks, such as regulatory, environmental, and operational risks will have a greater impact on the Company than it will have on its larger peers.

Capital Structure refers to the way a firm finances its overall operations through external debt and equity capital. Firms can reduce their Weighted Average Cost of Capital ("WACC") by recapitalizing and increasing their debt financing. Because interest expense is tax deductible, increasing debt also adds value to a firm by reducing the firm's tax obligation. Mr. Rush recommended the Company's proposed debt ratio of 50.3% debt and 49.7% equity. Additionally, Mr. Rush recommended Empire's proposed cost of debt of 5.30%.

The Commission should disallow 50% of short-term incentive compensation and 75% of long-term incentive compensation, and decrease the adjustment to payroll expense, which includes incentive compensation, in the amount of $50,777.53. The Company's plan is comprehensive, and includes both short-term and long-term incentives. The allowance of 25% of long-term incentives is appropriate to include in the overall compensation package of Empire and its recovery from consumers, and Mr. Rush believes that long-term incentives is an important part of employee retention as it requires continued employment to receive the full benefit of long-term incentive compensation programs.

Mr. Rush requested the Commission adopt the following recommendations:

1. A cost of equity of 9.90%, which is the midpoint in a range of reasonableness of 9.65% to 10.15%.
2. A cost of debt of 5.30%, as proposed by the Company.

3. A capital structure consisting of 50.3% debt and 49.7% equity.
4. An overall weighted average cost of capital of 7.59%, which is the midpoint in a range of reasonableness of 7.46% to 7.71%.
5. A decrease adjustment of $50,777.53 to reduce payroll expense, which includes incentive compensation.
6. The Company's requested increase adjustment to pension expense in the amount of $78,505.
7. The Company's requested decrease adjustment to Other Post Retirement Welfare Costs in the amount of $32,441.

These recommendations are fair, just, and reasonable to both ratepayers and the Company.

KIRAN PATEL

Responsive Testimony

Kiran Patel is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission"), and filed responsive testimony on March 13, 2017, in Cause No. PUD 201600468. The purpose of her testimony was to present PUD's recommendation regarding her assigned areas to The Empire District Electric Company ("Company"), for an adjustment in rates and charges for electric service in the State of Oklahoma for the 12 months ended June 30, 2016, as filed in Cause No. PUD 201600468.

Ms. Patel testified that she reviewed the following areas: Miscellaneous Taxes, Renewable Energy Credit Revenue, On-System Fuel and Purchased Power Expenses, Off-System Sales Margin and Revenue, Fuel Related O&M Expenses ("Operating and Maintenance" or "O&M"), Materials and Supplies and Fuel Inventories, Prepayments Expense, and Fuel Adjustment Rider.

Ms. Patel reviewed the Application, along with supporting testimony, workpapers, and prior rate cases. In addition, Ms. Patel issued data requests and reviewed data responses, general ledgers, trial balances, and other supporting documentation. Also, she had multiple teleconferences with Company representatives to clarify questions and/or issues.

Ms. Patel testified that after a thorough review of each assigned area, she recommended adjustments in four areas – Materials and Supplies, Fuel Inventories, Prepayments Expense, and Fuel Adjustment Rider Revenue. Ms. Patel further testified that she did not recommend adjustments to Miscellaneous Taxes, Renewable Energy Credit Revenue, On-System Fuel and Purchased Power Expenses, Off-System Sales Margin and Revenue, and Fuel Related O&M Expenses.

Overall, Ms. Patel recommended the Commission accept the adjustments stated in her testimony as described below.

1. Adjustment No. B-3 to bring the level of Materials and Supplies to a total of $740,507. This adjustment is an increase of $21,269.
2. Adjustment No. B-4 to bring the level of Fuel Inventories to a total of $815,218. This adjustment is a decrease of ($65,768).

3. Adjustment No. B-5 to bring the level of Prepayments Expense to a total of $249,712. This adjustment is an increase of $22,003.
4. A decrease of ($19,145) to Adjustment No. H-1 to Fuel Adjustment Rider Revenue.

Ms. Patel, after thorough review, believes these adjustments are fair, just, reasonable, and in the public interest.

ELBERT THOMAS

Responsive Testimony

Mr. Elbert Thomas is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission and filed Responsive Testimony on March 13, 2017, in Cause No. PUD 201600468. The purpose of Mr. Thomas's testimony is to present PUD's recommendation for his assigned areas in response to the Application filed by Empire District Electric Company ("Empire" or "Company").

Mr. Thomas recommended two adjustments in the areas of customer deposits and customer advances for construction.

He also reviewed areas including interest on customer deposits, contributions in aid of construction, franchise fees, and regulatory assets associated with the renewal of franchise tax. PUD did not recommend any adjustments in these areas.

For the areas of customer deposits and customer advances, Mr. Thomas recommended the following adjustments:

- **Customer Deposits:** Adjustment Number B–2a to increase customer deposits by $12,893. This will reduce the rate base by $12,893.
- **Customer Advances:** Adjustment Number B–6 to increase customer advances by $13,346. This will reduce the rate base by $13,346.

Mr. Thomas reviewed the areas of franchise fees and regulatory assets associated with the renewal of the franchise tax, customer deposits, interest on customer deposits, customer advances, and contributions in aid of construction. He also reviewed the application filed, along with testimony, prior rate cases, issued data requests, relevant statutes, and Commission rules. Mr. Thomas recommended the Commission accept the adjustments totaling $26,239 in customer deposits and customer advances. After a thorough review of each assigned area, Oklahoma Statutes and Commission rules, he believes this recommendation is fair, just, reasonable, and in the public interest.

JEREMY K. SCHWARTZ

Cost of Service

Responsive Testimony

Jeremy Schwartz is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Senior Public Utility Regulatory Analyst.

Responsive testimony of Mr. Schwartz, as a PUD witness regarding the cost of service ("COS") by The Empire District Electric Company ("Empire" or "Company"), was filed on March 22, 2017, in Cause No. PUD 201600468.

Mr. Schwartz's testimony addressed COS, its application in this Cause, and the impact of PUD's proposed accounting changes on customer classes. Also, his testimony addresses PUD's proposed revenue distribution and its impact on relative rates of return.

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

Mr. Schwartz stated that based on results of PUD's inputs to Empire's COS study, retail customers would be allocated a cost increase of $3,036,676.

Overall, Mr. Schwartz recommended the Commission approve the recommendations included in his testimony and he concluded that they are fair, just, and reasonable to both the Company and its ratepayers.

<u>Rebuttal Testimony</u>

Mr. Schwartz's rebuttal testimony addressed the proposed adjustments of the Office of the Attorney General of Oklahoma ("AG") and the Oklahoma Industrial Energy Consumers ("OIEC") regarding reliability in Oklahoma of The Empire District Electric Company.

Mr. Schwartz reviewed the testimony provided by the AG and OIEC in this Cause as it related to system reliability. Mr. Schwartz further reviewed Commission rules and workpapers relating to the system reliability of Empire.

Overall, Mr. Schwartz recommended Commission reject the recommendations and/or adjustments proposed by the AG and OIEC as they relate to system reliability. Instead, Mr. Schwartz testified that the Commission should accept his recommendation for the requirement of the Company to provide an in-depth analysis of its system reliability plan in its next rate case proceeding. This analysis would supplement the Company's annual reliability submissions to PUD and would include details on how the Company has and would continue to improve its reliability results. Mr. Schwartz further testified that the Commission, if not satisfied with the reliability results, could at that time make the adjustments it deems necessary in the cost of service and/or rate of return of the Company.

KATHY CHAMPION

<u>Rate Design</u>

<u>Responsive Testimony</u>

Kathy Champion is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. Responsive testimony of Ms. Champion, as a PUD witness regarding the revenue recovery in testimony filed on March 13, 2017, and the rate design by The Empire District Electric Company ("Empire" or "Company"), which testimony was filed on March 22, 2017, in Cause No. PUD 201600468.

Ms. Champion reviewed all information and testimony provided by the Company in this Cause related to the Annual Assessment Fee Rider and customer growth adjustments, the revenue recovery and rate design. Ms. Champion further reviewed Commission orders, testimony related to areas in prior causes, and workpapers relating to Empire. Ms. Champion communicated with the Company through email, phone calls, in-person reviews, electronic information/data requests and reviewed responses to these requests, along with an onsite audit.

Ms. Champion reviewed the Company's proposed revenue adjustment of $18,673 to remove the Annual Assessment Fee Rider revenues. In addition Ms. Champion reviewed the Company's proposed customer growth adjustment and while in agreement with the adjustment, Ms. Champion recommended an update to this adjustment to reflect the six-month post test year level of customers. Ms. Champion's recommendation increased the customer growth adjustment to revenues from the $7,148 proposed by the Company to $78,816.

Ms. Champion's testimony addressed the Company's proposed revenue recovery through the proposed revenue allocation and the proposed rate design changes as presented in the testimony of Company witness H. Edwin Overcast.

Ms. Champion presented PUD's recommendation on revenue recovery based on a concern that the Company's proposal exacerbates impacts on customers. Ms. Champion recommended that the Commission consider PUD's mitigation strategy as it attempts to balance the interests of both the Company and its customers.

Ms. Champion testified that she utilized the modified revenue allocation presented by PUD witness Jeremy Schwartz and recommended a revenue recovery that phases in PUD's allocated revenue increase over four (4) years.

Ms. Champion's testimony also addressed the Company's proposed rate design changes, and recommended only minor changes in rate design.

Overall, Ms. Champion recommended the Commission approve the recommendations included in her testimonies and believes that they are fair, just, and reasonable to both the Company and its ratepayers.

MCKLEIN AGUIRRE

<u>Responsive Testimony</u>

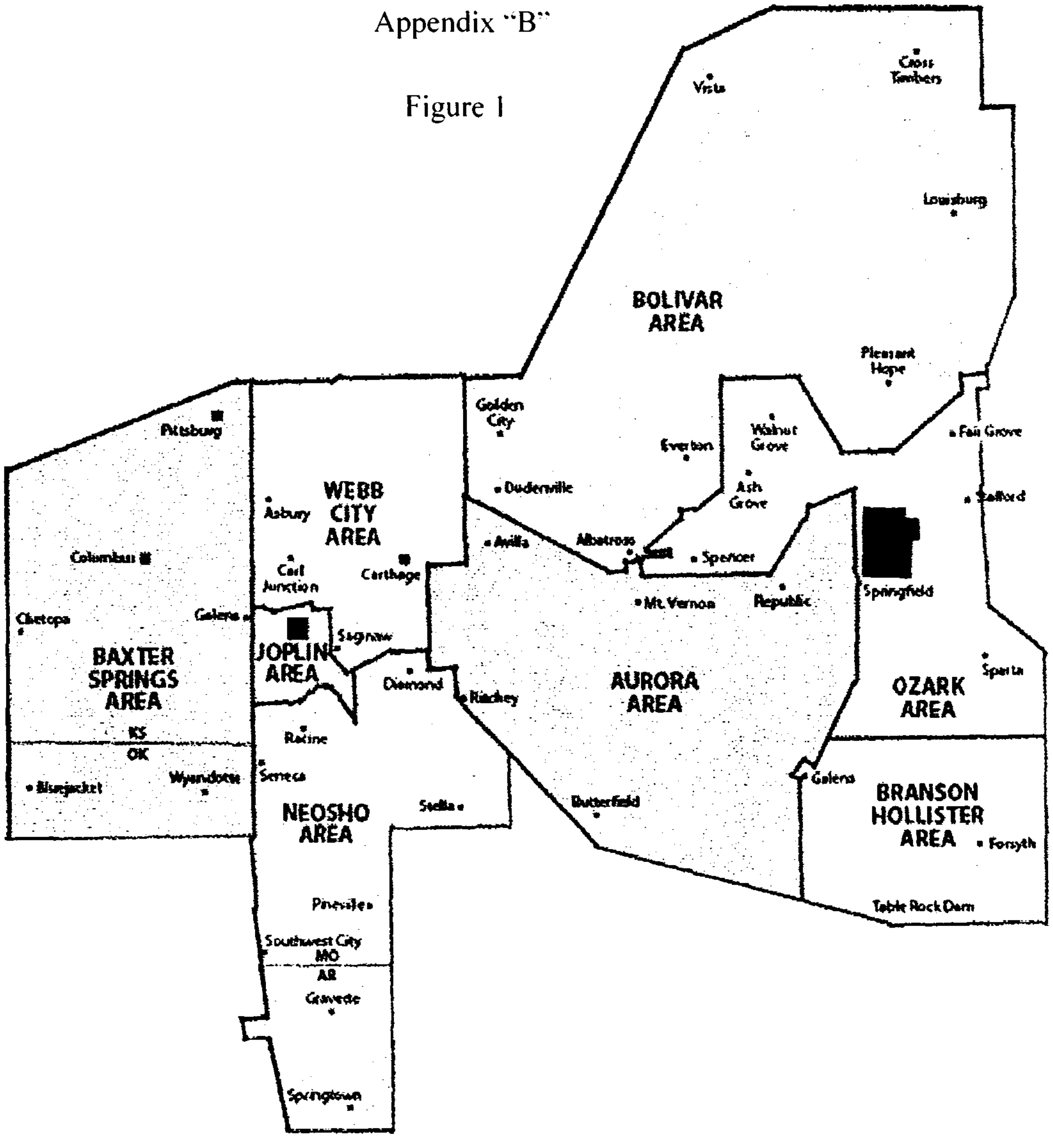
Mr. McKlein Aguirre is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") and filed Responsive Testimony on March 13, 2017, in Cause No. PUD 201600468. The purpose of Mr. Aguirre's testimony was to present PUD's recommendation pertaining to cost recovery of the expenses included in Dues and Donations in response to the Application filed by Empire District Electric Company ("Empire" or "Company").

Mr. Aguirre reviewed the areas of Marketing and Sales Expenses, Dues, Donations, Civic, and Membership Expenses, Advertising Expenses, and Legislative Advocacy. Along with conducting an onsite audit at the Company's headquarters in Joplin, Missouri, Mr. Aguirre also reviewed the application filed, along with testimony, prior rate causes, relevant statutes, Commission rules, and issued a data request.

After a thorough review of each assigned area, Mr. Aguirre recommended that the Commission accept one adjustment to reduce Dues and Donations by $69,467.95. Mr. Aguirre believed the recommended adjustment is fair, just, reasonable and in the public interest. Mr. Aguirre did not recommend any adjustments for the other areas he reviewed. Those areas included Marketing and Sales Expenses, Advertising Expenses, and Legislative Advocacy.

Appendix "B"

Figure 1



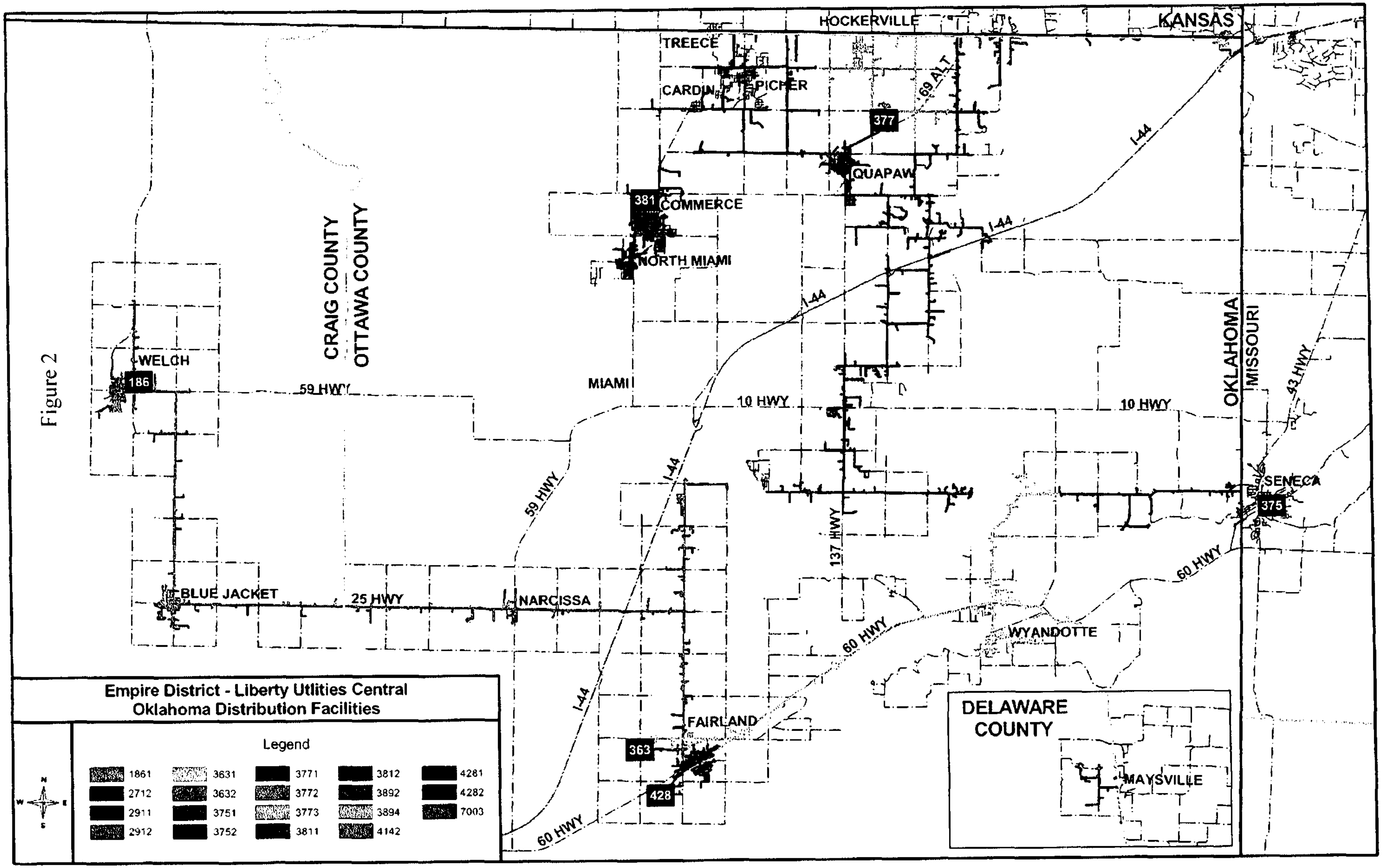
The Empire staff, along with our community partners, will assist you in your business expansion or relocation. Use the links below to access community profiles and available industrial buildings and sites:

All

- ✔ Communities / Localities
- ✔ Buildings
- ✔ Sites

Arkansas

Figure 2


HOCKERVILLE
KANSAS
TREECE
CARDIN
PICHER
69 ALT
377
I-44
QUAPAW
381
COMMERCE
I-44
NORTH MIAMI
CRAIG COUNTY
OTTAWA COUNTY
I-44
WELCH
186
59 HWY
MIAMI
10 HWY
10 HWY
OKLAHOMA
MISSOURI
43 HWY
I-44
59 HWY
SENECA
375
137 HWY
60 HWY
BLUE JACKET
25 HWY
NARCISSA
60 HWY
WYANDOTTE
I-44
FAIRLAND
363
428
60 HWY
DELAWARE
COUNTY
MAYSVILLE
Empire District - Liberty Utlities Central
Oklahoma Distribution Facilities
Legend
1861
2712
2911
2912
3631
3632
3751
3752
3771
3772
3773
3811
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3894
4142
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Table 5										
		Balance to be Allocated	**Res**	**Comm**	**Tot.Elec. Bldg**	**Gen Pow**	**Pow Trans**	**Street Lts**	**Private Lts**	**Spec Lts**
Current	Operating Revenues	9,101,914	3,425,986	1,174,544	212,611	1,668,785	2,362,216	49,241	204,049	4,482
Current	Less Other Rate Revenues	573,460	266,740	54,287	11,694	79,604	157,204	1,676	1,955	301
Current	Rate Revenues	8,528,454	3,159,246	1,120,257	200,918	1,589,180	2,205,012	47,566	202,094	4,181
ALJ	Proposed Revenues	11,731,195	4,415,654	1,513,836	274,029	2,150,848	3,044,592	63,466	262,993	5,777
ALJ	Other Revenues	573,460	266,740	54,287	11,694	79,604	157,204	1,676	1,955	301
ALJ	Rate Revenues	11,157,735	4,148,915	1,459,549	262,335	2,071,244	2,887,388	61,790	261,038	5,476
ALJ	Base Rate Increase	31%	31%	30%	31%	30%	31%	30%	29%	31%
Empire	Original proposed revenues	12,798,728	5,157,442	1,488,590	272,216	2,055,555	3,570,165	75,299	203,765	6,773
Empire	Less oher revenus	573,460	266,740	54,287	11,694	79,604	157,204	1,676	1,955	301
Empire	Proposed base rate revenues	12,256,345	4,890,703	1,434,303	260,523	1,975,951	3,412,961	73,623	201,810	6,472
Empire	proposed base rate increase	44%	55%	28%	30%	24%	55%	55%	0%	55%