BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	)	CAUSE NO.: PUD 201500273 ORDER NO. **662059**

FINAL ORDER

HEARING: February 2, 2017, Hearing before the Commission *en banc* on Exceptions to the Report of the Administrative Law Judge on the Full Evidentiary Hearing and Errata Appendix C Page 285

APPEARANCES: Kimber L. Shoop, Patrick D. Shore, and William L. Humes, Attorneys representing Oklahoma Gas and Electric Company

Natasha M. Scott and Judith L. Johnson, Attorneys representing the Public Utility Division, Oklahoma Corporation Commission

Dara M. Derryberry, Assistant Attorney General, representing the Office of the Attorney General, State of Oklahoma

Thomas P. Schroedter, Attorney representing Oklahoma Industrial Energy Consumers

Ronald E. Stakem and Jack G. Clark, Jr., Attorneys representing OG&E Shareholders Association

Deborah R. Thompson, Attorney representing AARP and Oklahoma Sustainability Network

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

Cheryl A. Vaught, Attorney representing Oklahoma Energy Results, LLC

Jim A. Roth and Marc Edwards, Attorneys representing The Alliance for Solar Choice, the Oklahoma Hospital Association and the Wind Coalition

Lee W. Paden, Attorney representing Citizen Potawatomi Nation

Thomas A. Jernigan, Attorney representing Federal Executive Agencies

Jacquelyn L. Dill and Casey Roberts, Attorneys representing Sierra Club

BY THE COMMISSION:

The Corporation Commission of the State of Oklahoma ("Commission") being regularly in session and the undersigned Commissioners being present and participating, there comes on for consideration and action the above-styled and numbered cause.

I. PROCEDURAL HISTORY

The procedural history of this cause through the date of the hearing held before the ALJ is found in the Report of the ALJ on the Full Evidentiary Hearing filed December 8, 2016, to which Errata Appendix C page 285 was filed December 16, 2016 (together referred to hereafter as "ALJ Report").

The following events occurred since the filing dates of the ALJ Report:

On January 3, 2017, the Federal Executive Agencies ("FEA") filed Exceptions to the ALJ Report and a Motion for Oral Argument.

On January 4, 2017, Oklahoma Gas and Electric Company ("OG&E") filed Exceptions to the ALJ Report, a Motion for Oral Argument and a Notice of Hearing.

On January 4, 2017, the Public Utility Division ("PUD") filed Exceptions to the ALJ Report, Motion for Oral Argument and Notice of Hearing.

On January 4, 2017, the Attorney General ("AG") filed Exceptions to the ALJ Report , a Motion for Oral Argument and a Notice of Hearing.

On January 4, 2017, Oklahoma Industrial Energy Consumers ("OIEC") filed Exceptions to ALJ Report.

On January 4, 2017, Oklahoma Energy Results, LLC ("OER") filed Exceptions to the ALJ Report and a Motion for Oral Argument.

On January 4, 2017, AARP filed Exceptions to the ALJ Report.

On January 11, 2017, OG&E filed its Response to Exceptions to the ALJ Report.

On January 11, 2017, OIEC filed its Response to OG&E's Exceptions to ALJ Report.

On January 11, 2017, OER filed its Response to OG&E's Exceptions to the ALJ Report.

On January 11, 2017, Citizen Potawatomi Nation (CPN) filed its Response to Exceptions filed by Parties on January 4, 2017.

On January 11, 2017, Wal-Mart Stores East, LP, and Sam's East, Inc. filed their Response to Exceptions to the ALJ Report.

On January 11, 2017, The Oklahoma Hospital Association ("OHA") filed its Response to the Exceptions filed by OG&E to the ALJ Report.

On January 11, 2017, The Alliance for Solar Choice ("ASC") filed its Reply to Exceptions filed by OG&E.

On January 17, 2017, Sierra Club filed its Responses to Exceptions to the ALJ Report.

II. SUMMARY OF EVIDENCE

The summary of evidence is contained in the ALJ Report as Appendix A.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

The Commission has jurisdiction over this matter by virtue of Article IX, Section 18, of the Oklahoma Constitution, 17 O.S. §§ 151 *et seq.*, and the rules of the Commission.

Notice of these proceedings was proper and was given as required by law and the orders of the Commission.

In the exercise of its legislative, judicial and executive powers, the Commission is required to reach its own conclusions based upon the evidence before it, and it may adopt, reject, restrict, or expand any or all findings and recommendations of the ALJ. *State ex rel. Cartwright*

v. Oklahoma Natural Gas Co. and Oklahoma Corporation Commission, 1982 OK 11, ¶8,; *Smith Cogeneration Mgmt., Inc. v. Corp. Comm'n*, 1993 OK 147, ¶14; *Cameron v. Corp. Comm'n*, 1966 OK 75, ¶29.

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

Allowed Return on Equity (P. 21, ALJ Report)

The Commission does not agree with the reasoning utilized by the ALJ in determining his recommended Return on Equity ("ROE"), including his heavy reliance upon the Texas Public Utility Commission's order for Southwest Public Service Company (Hearing Exhibit 61). Rather than the 9.87 percent recommended by the ALJ, the Commission adopts an ROE of 9.50 percent. This ROE is the midpoint of the range of OIEC witness Parcell's comparable earnings analysis (Parcell Responsive, beginning pg. 27), is within the range of AG witness Solomon's discounted cash flow analysis (Solomon Responsive, beginning pg. 34), is within the range of FEA witness Walters' risk premium analysis (Walters Responsive, beginning pg. 32), and is also within the range of his capital asset pricing model (Walters Responsive, beginning pg. 37).

The Commission does not come to this conclusion lightly. It has not given more weight to the cited witnesses' ROEs as opposed to the 10.25 percent recommended by OG&E's witness Mr. Hevert simply because of a three-against-one bias as was suggested could happen by OG&E's counsel during oral argument. The decision on ROE was formed based on a review and weighing of the opinions set forth by all ROE witnesses and the evidence asserted by them that

supported their opinions. Specifically, in this Cause, the Commission did not find Mr. Hevert's opinions persuasive. His recommended ROE of 10.25 percent was excessive in that each of his methods and the inputs he used appear to have been biased upward, resulting in a significantly inflated recommendation. The Commission has reviewed all the testimony, including all models utilized by each ROE witness, and has given full consideration to the oral argument in rendering its opinion. The Commission rejected those models that were above and/or below a reasonable range and concludes that the 9.50 percent ROE determined herein is fair, just and reasonable to both ratepayers and OG&E. Further, a 9.50 percent ROE will afford OG&E the opportunity to earn a fair and reasonable rate of return. The Commission has undertaken a concerted effort to balance the interests of both the investor and the consumer and believes that the 9.50 percent ROE will be sufficient to allow OG&E to maintain and support its credit, assure confidence in its financial integrity and allow it to continue to attract capital.

Capital Structure and Cost of Debt (P. 31, ALJ Report)

The Commission accepts the ALJ's recommendation to allow the actual capital structure of OG&E. (ALJ Report, pp. 32 & 33). This would allow the current capital structure of 53.31 percent equity and 46.69 percent debt. Also, the Commission accepts the ALJ's recommended cost of debt at 5.62 percent. (ALJ Report, pp. 31 & 33).

Despite accepting the recommendation of the ALJ, the Commission is concerned with OG&E's current equity to debt ratio, which is not in line with averages of other utilities. OG&E should further evaluate adjusting its equity to debt ratio to maximize the benefits of lower cost debt, similar to that of other utilities, by its next base rate proceeding. The Commission will be closely reviewing OG&E's weighted average cost of capital in a future base rate proceeding and

is not opposed to considering utilizing a hypothetical capital structure for OG&E if sufficiently persuaded based upon the evidence presented in that case.

Overall Rate of Return (P. 33, ALJ Report)

Based upon the 9.50 percent ROE as determined above, 5.62 percent cost of debt, and the capital structure of 53.31 percent equity and 46.69 percent debt, OG&E's authorized stated Rate of Return or ROR is 7.688 percent.

Rate Base (P. 33, ALJ Report)

Rate base and its components—including but not limited to Plant in Service, cash working capital, accumulated deferred income tax, accumulated depreciation, and net utility plant— are to be adjusted based on the determinations made throughout this order.

Based upon the ALJ Report and the adjustments made by this Order, the Oklahoma jurisdictional rate base, for the purpose of base rates calculation, shall be $4,202,129,058.

Revenue and Expenses (P. 41, ALJ Report)

Revenue and expenses—including but not limited to taxes, interest synchronization, depreciation, and incentives—are to be adjusted based on the determinations made throughout this order.

TeamShare Expense (P. 43, ALJ Report)

Short-Term Incentive Compensation (P. 43, ALJ Report)

The Commission declines to adopt the recommendation of the ALJ for recovery of one

hundred percent of the maximum amount of short-term incentive compensation of $14,209,108. In this cause, sufficient support was not provided by OG&E or PUD to move to allowing full recovery for short-term compensation beyond what has been historically awarded. Instead, based on the record before it, the Commission finds that fifty percent of short-term incentive compensation is appropriate. In future causes, the Commission will again evaluate the manner in which short-term incentive compensation is awarded.

Long-term Incentive Compensation (P.44, ALJ Report)

The Commission declines to adopt the recommendation of the ALJ for recovery of twenty-five percent of long-term incentive compensation. In this cause, the Commission is not persuaded that such compensation provided benefit to ratepayers. Therefore, no recovery is given for long-term incentive compensation.

Vegetation Management (P. 47, ALJ Report)

The Commission does adopt the ALJ's recommendation to deny a vegetation management tracker; however, in lieu of the findings and recommendations set forth on page 49, the Commission finds that OG&E witness Mr. Cassada was the most knowledgeable witness in the area of vegetation management, and therefore adopts OG&E's vegetation management expense request. Moreover, Mr. Rowlett's direct testimony cited at page 47 of the ALJ Report sets forth the increase in distribution assets and growth in transmission underlying OG&E's request for increased vegetation management expenses. This growth combined with the ongoing requirement to provide high quality, reliable electric service supports the request for increased vegetation management expense. The Commission further declines to adopt the ALJ's findings

regarding herbicide expense because these findings mischaracterize the testimony of Mr. Cassada as noted in OG&E's January 4, 2017, Exceptions at page 18.

Depreciation (P. 55, ALJ Report)

The Commission does not agree with the ALJ's recommendation regarding depreciation expense. The testimony offered by OG&E's depreciation witness, Mr. Spanos, is lacking in sufficient detail and support to justify the increased depreciation levels sought by OG&E. Particular areas include decommissioning expense associated with generating facilities as well as OG&E's request for Holding Company depreciation expense. The Commission adopts the depreciation rates proposed by OIEC/OER witness Jacob Pous and PUD witness David Garrett and finds their proposed depreciation rates to be reasonable.

OG&E had proposed a total depreciation expense of $314,602,372. Mr. Jacob Pous' recommended changes to OG&E's depreciation study resulted in a reduction of $41,014,841 to OG&E's total depreciation expense (3-21-16 Responsive testimony of Mark E. Garrett, P. 61; and Exhibit MG-2.10). However, his analysis only addressed the depreciation rates for transmission, generation and general assets. Mr. David Garrett, on behalf of the PUD, had made a similar recommendation to reduce OG&E's total depreciation expense by $14,387,949 (Transcript, Testimony of David Garrett, 5-18-16 Evening Session, pp. 41-42; and, Hearing Exhibit 75). His analysis addressed the depreciation rates for all distribution assets. Together, those two adjustments (totaling $55,402,790) addressed depreciation for all of OG&E's plant assets.

Based upon the above, OG&E's total depreciation expense allowed in this cause would be $259,199,582. However, that total adjustment to OG&E's requested depreciation expense requires further adjustment.

The OIEC/OER and PUD witnesses both agreed that OG&E's wind farms should be depreciated based on a 30 year life span and their respective recommended reductions were based upon that assertion. The Commission does not accept the 30 year life span for the wind farms and agrees with the ALJ's recommendation to continue to depreciate those wind farm assets on the 25 year life span that is currently being utilized. Therefore, the combined total reduction of $55,402,790 recommended by OIEC/OER and PUD should be adjusted (reduced) by the amount of $6,536,674 (from March 21, 2016, testimony of Jacob Pous, P. 36, ln. 5) which is the depreciation expense that would increase based on that 5 year change in wind farm life span.

Based upon the above, OG&E's total depreciation expense allowed in this cause should be $265,736,256 as shown below.

OG&E proposed depreciation expense	$ 314,602,372
less OIEC/OER adjustment	($ 41,014,841)
less PUD adjustment	($ 14,387,949)
plus wind farm life span adjustment	$ 6,536,674
total depreciation expense	$ 265,736,256

Finally, the Commission finds, as was suggested by Mr. Pous, that OG&E should "provide a detailed narrative explaining, supporting, and justifying each of its life and net salvage proposals in its next depreciation study. The level of transparency and detail expected should be such that the reader can identify what the most significant or meaningful specific items of information relied upon were for each proposal, not generalized references to statistical analyses or discussions with Company personnel. In addition, the presentation should include

the underlying documentation and work papers that support the most significant or meaningful specific items of information relied upon, especially those that relate to information pertaining to the outlook or expectations of management." (March 21, 2016, testimony of Jacob Pous, P. 15, ln. 8)

Fuel Adjustment Clause ("FAC") Issues (P. 67, ALJ Report)

Air Quality Control Systems Consumable Costs ("AQCS")

The Commission declines to adopt the recommendation of the ALJ to disallow OG&E's request to recover the AQCS in the FAC. The ALJ based that recommendation upon the Commission's decision in Order No. 647346, issued in OG&E Cause No. 201400229 where the Commission denied a similar request. However, in that order, although the Commission stated there was not a sufficient basis for recovering those costs through the FAC in that case, the Commission also stated that "it would be more appropriate for OG&E to seek, and the Commission to consider, this type of modification of its FAC Tariff in a general rate proceeding." (Order No. 647346, ¶ H, p. 17).

The Commission finds that environmental consumables are used in the generation of electrical energy and their consumption rates are variable and highly correlated to the amount of fuel consumed and electrical generation produced, and that OG&E provided substantial evidence supporting that finding. The Commission further finds that the evidence provided by OG&E supports the need to recover such costs through the FAC and determines that OG&E's request to include such costs in the FAC should be approved.

Production Tax Credits ("PTCs")

The Commission declines to adopt the recommendation of the ALJ that OG&E needs to apply for a rider or a regulatory asset to deal with expiring PTCs. Certain PTC credits are expiring and the impact of their expiration is known and measurable. When these PTCs expire, because they are currently contained in base rates, if they are not moved to the FAC (or some other tracker) their expiration will substantially reduce the revenue that OG&E would otherwise be entitled to receive from approved rates.

The Commission agrees in part with OG&E's assertion that from a practical perspective, as well as a regulatory efficiency perspective, it makes sense to move expiring PTCs from base rates to the FAC, but at this time, only those expiring in 2017. Moving the PTCs expiring in 2017 into the FAC would allow customers to receive the credits associated with PTCs and allow OG&E to adjust the PTC credits as they expire. Evidence showed that the amount of PTCs generated are (i) highly variable and directly tied to the volume of energy produced from the wind farms; (ii) wind power is commonly referred to as "variable renewable energy" in that it is non-dispatchable due to its fluctuating nature; (iii) wind generation output varies by hour, day, month, and season; and, (iv) because PTCs are directly related to production and that production is variable, it is appropriate to include PTC credits in the FAC (Rowlett Rebuttal, p. 14, lns. 14-20). Finally, the Commission recognizes that the PUD undertakes an annual review of OG&E's FAC and, therefore, a review process is in place for timely and thorough reviews. For all these reasons, the Commission agrees that the FAC is an appropriate mechanism for passing through the PTC credits expiring in 2017.

Therefore, the Commission finds that OG&E's request to move its expiring PTCs into the FAC should be approved in part, and hereby limits recovery through the FAC to those PTCs that

expire in calendar year 2017 in the amount of $9,098,913 (Rowlett Rebuttal, p. 13, lns. 22-24). However, that amount is the total of PTCs for the entire Company. This amount, adjusted to the Oklahoma jurisdiction at 90.917% is $8,272,450. The treatment of any PTCs expiring subsequent to calendar year 2017 are to be determined in OG&E's next base rate proceeding or another cause OG&E might file to deal with these issues.

Rate Design (P. 74, ALJ Report)

The Commission has reviewed the recommendations of the ALJ regarding the non-unanimous Joint Stipulation and Settlement Agreement as to Certain Rate Design, Cost of Service, and Fuel Adjustment Issues filed herein on May 23, 2016 ("Stipulation") (Appendix B to the ALJ Report). In addition, the Commission has reviewed the Stipulation, OG&E's Response to the Stipulation filed May 25, 2016, as well as the testimony presented in regard to the Stipulation at the hearing. The Commission finds that the Stipulation should be and hereby is adopted by the Commission, *subject* to the changes and modifications set forth below. The Commission further finds that the Stipulation, as modified, is just, reasonable and in the public interest. The Commission also accepts the recommendations of the ALJ in the Rate Design section of the report beginning on page 74, but as stated previously, does not accept any recommendations or statements inconsistent with adopting the Stipulation as modified.

As to paragraph 1.b., on page two of the Stipulation, the Commission agrees with OG&E's suggested terminology change so that this sentence will now read as follows:

> **1. No New Demand Charges.**
>
> b. Before proposing the introduction of any new demand charges, OG&E will be required to provide a cost of service study of small, medium, and large users within major rate classes not currently containing a demand charge.

As to paragraph 1.c., beginning on page two of the Stipulation, the Commission agrees in part with OG&E's suggested changes so that this paragraph will now read as follows:

> **1. No New Demand Charges.**
>
> c. Before proposing the introduction of any new demand charges for any rate class, not currently subject to a demand charge, OG&E will conduct a study and pilot program on demand charges to evaluate customer acceptance, understanding, and ability to respond to a rate design that includes demand charges and appropriate methods for recovering fixed costs. The results will be evaluated from various perspectives, including, but not limited to, customer satisfaction and acceptance, impact on low income and senior citizens, customer ability to respond to a rate design that includes a demand charge, conservation, ability for accurate cost recovery, economic efficiency, bill stability, and contribution to system peak. OG&E will also be required to provide bill impact analysis for participating small, medium, and large users.
>
> The study will be designed and evaluated by an independent third party with guidance from the Company and PUD staff. The reasonable costs of the pilot, including the design and evaluation thereof, will be recovered through the DPR tariff upon approval of new, introduced demand charges.

As to paragraph 3.d., on page three of the Stipulation, the Commission modifies the language, so that this paragraph will now read as follows:

> **3. Distributed Generation Customers – Residential and Small Commercial.**
>
> d. In the event OG&E proposes, in the future, a demand charge or any other substantive change to a tariff applicable to customers with distributed generation that OG&E deems necessary to comply with 17 O.S. § 156, the Commission will require OG&E to include as part of its case cost effectiveness tests, such as those performed for the company's demand programs, and make available to the parties detailed cost and benefit data.

As to paragraph 6.b.ii., on page six of the Stipulation, the Commission agrees with OG&E's suggested change so that this sentence will now read as follows:

> **6. PayGo Prepay Billing Option.**

ii. Frequency and duration of PayGo disconnections by month, which will include additional explanation of any reconnections taking longer than 15 minutes after payment has been received.

As to paragraph 7.a., on page seven of the Stipulation, the Commission agrees with OG&E's suggested change so that this sentence will now read as follows:

7. Automated Metering (Smart Meter) Opt Out Tariff.

a. Automated Metering (Smart Meter) Opt Out Tariff, as requested in the Application in this Cause, will be implemented.

Interim Rate Refund

The Commission finds that on June 28, 2016, pursuant to 17 O.S. § 152(B)(4), OG&E implemented an interim rate adjustment applicable to the base rate charges of all of OG&E's retail customers. The Commission further finds that OG&E's interim rate adjustment was implemented subject to refund. The Commission finds that a refund to customers of OG&E's interim rate adjustment is appropriate and necessary to the extent it exceeds the rates approved by this Final Order. The Commission orders that the refund shall include reasonable interest at the one-year U.S. Treasury Bill rate consistent with 17 O.S. § 152(B)(5), and shall be credited to OG&E's customers. The refund, with interest as provided by 17 O.S. § 152(B)(5), shall be credited to customer classes using the same allocation method by which the interim rates were collected. The refund shall be given to customer classes through adjusted tariff rates through December 2017 and shall be reflected by a line-item credit on customers' bills as soon as possible, beginning no later than May 1, 2017.

The Commission further finds and orders OG&E to provide refunds to customers who left the OG&E system prior to the credit ordered by the Commission. The refund shall be available to those former customers who paid the interim rates. The refund shall be calculated

on an average customer monthly impact by class. The former customers' refund shall be the average monthly impact multiplied by the number of months they paid under interim rates. Only customers who ended service without starting new service on the OG&E system are eligible for a one-time refund. Former customers not in good payment status will first have their accounts credited, then any remaining refund balance will be provided to them. Former customers shall have six months from the date of this Order to request a refund from OG&E. Thereafter, any remaining funds shall be included in the deferred fuel account and credited immediately to OG&E's fuel expense for the benefit of all customers. The Commission further directs OG&E to immediately issue press releases in its service areas to inform former customers of any potential refund.

OG&E shall submit a report monthly to the PUD Director reflecting the refund ordered herein.

The Final Order Accounting Schedule, appended hereto as Attachment 1, reflects the adjusted base rate revenue amount in accordance with the findings set forth above.

ORDER

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA that the ALJ Report appended hereto as Attachment 2, subject to and as modified or superseded by the exceptions and modifications detailed hereinabove, is hereby adopted and incorporated herein as if fully set forth, as the order of the Commission, and the ALJ's rulings on motions in the Cause are affirmed.

IT IS FURTHER ORDERED that OG&E shall, within two weeks after the date of this Order, submit to the Director of the Public Utility Division tariffs consistent with the findings set

forth herein, and that the rates, charges, and tariffs shall be effective with the first regular billing cycle after such tariffs are approved by the Director of the Public Utility Division.

OKLAHOMA CORPORATION COMMISSION

Dana L. Murphy

DANA L. MURPHY, Chairman

Concur in Result,
Concurring Statement to be Filed

J. TODD HIETT, Vice Chairman

Bob Anthony

BOB ANTHONY, Commissioner

DONE AND PERFORMED this 30th day of March, 2017.

BY ORDER OF THE COMMISSION:

Joyce Conner

~~PEGGY MITCHELL, Secretary~~
JOYCE CONNER, Assistant Secretary

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 201500273
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

ATTACHMENT 1
FINAL ORDER ACCOUNTING SCHEDULE

Oklahoma Gas and Electric Company
Final Order Revenue Requirement
Test Year Ended June 30, 2015
Cause No. PUD 201500273

Line No.	Description	(A) OGE Total Company Pro Forma Amount	Reference	(B) Final Order Total Company Adjusted Amount	(A) OGE Oklahoma Pro Forma Amount	Reference	(B) Final Order Total Company Adjusted Amount
1	Pro Forma Rate Base	$ 4,631,488,154	B-1	$ 4,685,757,529	$ 4,152,329,406	B-1	$ 4,202,129,058
2	Rate of Return	8.088%	F-1	7.688%	8.088%	F-1	7.688%
3	Operating Income Required	$ 374,594,762	1 times 2	$ 360,241,039	$ 335,840,402	1 times 2	$ 323,059,682
4	Pro Forma Operating Income	$ 267,250,990	H-1	$ 460,265,446	$ 244,277,578	H-1	$ 409,364,559
5	Difference	$ 107,343,772	3 minus 4	$ (100,024,407)	$ 91,562,824	3 minus 4	$ (86,304,877)
6	Revenue Conversion Factor	1.633266		1.630768	1.633266		1.630768
7	**OGE Pro Forma Base Rate Revenue Increase/(Decrease)**	**$ 175,320,933**	5 times 6		**$ 149,546,447**	5 times 6	
8	**Final Order Proposed Change to OGE Requested Base Rate Revenue Increase/(Decrease)**		5 times 6	**$ (163,116,602)**		5 times 6	**$ (140,743,232)**
9	**Final Order Pro Forma Base Rate Revenue Increase/(Decrease)**		7 minus 8	**$ 12,204,331**		7 minus 8	**$ 8,803,215**
10	Rev Inc Minus Difference	$ 67,977,161		$ (63,092,195)	$ 57,983,623		$ (54,438,355)
	Revenue Requirement						
11	Return Requirement	$ 374,594,762	Line 3	$ 360,241,039	$ 335,840,402	Line 3	$ 323,059,682
12	Total Operating Expense	$ 896,245,022	H-1	$ 823,400,063	$ 826,943,794	H-1	$ 760,350,810
13	Income Taxes	$ 152,961,736		$ 77,043,816	$ 137,136,790		$ 81,139,262
14	**Revenue Requirement**	$ 1,423,801,520	Line 11+12+13	$ 1,260,684,918	$ 1,299,920,986	Line 11+12+13	$ 1,164,549,754

Section B
Schedule 3

Oklahoma Gas and Electric Company
Explanation of Final Order Adjustments to Rate Base
Test Year Ended June 30, 2015
Cause No. PUD 201500273

Final Order Adj. No.	Adjustment Description	(A) Impact On Rate Base Increase	(B) Impact On Rate Base Decrease	(C) Net Incr/(Decr)
1	To adjust Plant in Service to 12/31/15 Balances	$ 13,883,825		
2	To adjust Accumulated Depreciation to 12/31/15 Balances	$ 32,037,383		
3	To Adjust Materials and Supplies level		$ (872,170)	
4	To adjust Gas In Storage Inventory	$ 857,885		
5	To Adjust Fuel Inventories	$ 19,673,909		
6	To Adjust Customer Deposit	$ (1,246,132)		
7	To adjust Cash Working Capital to reflect Final Order Adjustments		$ 662,204	
8	Prepayments	$ 87,331		
9	ARO 6 month update		$ (3,839,228)	
10	Net pension benefit		$ (6,982,940)	
11	ADIT		$ 815,847	
12	Plant held for future use		$ 273,615	
13	Gain on sale of assets		$ (1,082,154)	
	Total Rate Base Adjustments	**$ 65,294,201**	**$ (11,024,826)**	**$ 54,269,375**

Oklahoma Gas and Electric Company
Capital Structure
Test Year Ended June 30, 2015
Cause No. PUD 201500273

Line No.	Description	(A) OGE Capitalization Ratios	(B) OGE Cost of Capital	(C) OGE Weighted Cost of Capital
	OGE Requested Capital Structure:			
1	Long Term Debt	46.690%	5.600%	2.615%
2	Preferred Stock	0.000%	0.000%	0.000%
3	Common Stock	53.310%	**10.250%**	5.464%
4	Total	100.000%		8.079%

Line No.	Description	Final Order Capitalization Ratios	Final Order Cost of Capital	Final Order Weighted Cost of Capital
	Final Order Capital Structure:			
1	Long Term Debt	46.690%	5.620%	2.624%
2	Preferred Stock	0.000%	0.000%	0.000%
3	Common Stock	53.310%	**9.500%**	5.064%
4	Total	100.000%		7.688%

Oklahoma Gas and Electric Company
Explanation of Final Order Adjustments to Operating Income
Test Year Ended June 30, 2015
Cause No. PUD 201500273

Final Order Adj. No.	Adjustment Description	(A) IMPACT ON REVENUE REQUIREMENT Decrease	(B) IMPACT ON REVENUE REQUIREMENT Increase	(C) IMPACT ON REVENUE REQUIREMENT Net Incr/(Decr)
1	Rate Case expenses	$ (262,819)		
2	To adjust Depreciation Expense	$ (48,866,116)		
3	Regulatory expenses	$ (457,422)		
4	To Adjust Bad Debt Expense	$ (27,418)		
5	Payroll Adjustment	$ (565,523)		
6	Payroll Tax Adjustment	$ (37,096)		
7	Long-Term, Short-Term and SERP Adjustment	$ (16,093,531)		
8	Dues and Donations	$ (115,673)		
9	Ad Valorem Tax	$ (4,624,225)		
10	To adjust demand program advertising	$ (537,115)		
11	To increase Customer Deposit Interest		$ 18,205	
12	Outside Services	$ (295,788)		
13	Enable	$ (2,118,759)		
14	Amortize Gain on Sale of McLain Rotor		$ 32,083	
	Total Adjustments to operating income	**$ (74,001,485)**	**$ 50,288**	**$ (73,951,197)**

ATTACHMENT 2

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	)	CAUSE NO. PUD 201500273

REPORT OF THE ADMINISTRATIVE LAW JUDGE ON THE FULL EVIDENTIARY HEARING

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I. EXECUTIVE SUMMARY

On July 28, 2015, Oklahoma Gas and Electric Company ("OG&E" or "Company") filed a notice of intent to file a rate case. Due to circumstances, including bad weather, OG&E filed its rate case application package on December 18, 2015, requesting an increase of $92,494,692 in order to earn a 10.25 percent return on equity and an overall return of 8.088 percent on an Oklahoma jurisdictional rate base of $4,152,329,406. A total of 15 other parties, including the Oklahoma Attorney General ("AG"), the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") and the OG&E Shareholders Association ("OG&E Shareholders") entered the proceeding. One entity, Voices Organized in Civic Engagement ("VOICE") limited its activity to public comment.

In essence, the cause was divided into two segments. One addressed the revenue requirements of the utility while the other dealt with rate design that is how any resulting increase or decrease would be distributed across the various customer classes. Fourteen parties actively participated in the hearing process with the OG&E Shareholders supporting the utility's position and the other 13 recommending a variety of changes. Of the 13, six filed proposed orders dealing with revenue requirements, while all parties dealt with rate design issues.

On pages five and six of his prefiled Direct Testimony, Don Rowlett, OG&E's Managing Director of Regulatory Affairs, summarized the utility's rate request as follows:

a. 1.6 billion in new infrastructure at requested ROE of 10.25 makes up 30.6 million of request.

b. There is $60.2 million in depreciation broken down as: $44.6 million in increased depreciation for new facilities and new rates, and $15.6 million for terminal net salvage also called dismantling. Since current depreciation rates contain net salvage the total dismantling cost is over $18 million;

c. An additional $16.5 million is for transferring 300 megawatts of generating capacity formerly dedicated to wholesale contracts into serving retail customers;

d. There is $29.7 million in increased operating costs with the major portions being $11.2 million increase in vegetation management and $10.9 million in increased maintenance and labor costs;

e. There is $9.5 million to cover additional income taxes for a total of $146.5 million; and

f. Credited against the total is $54 million in increased revenue from customers.

Oklahoma Statute 17 O.S. 2011 §284 requires the Commission to consider changes occurring within six months of the close of the historic test year. The six-month post test year period closed in this cause on December 31, 2015. During the hearing process, OG&E accepted 20 adjustments to its filing, reducing its request to $85,650,940. Sixteen of these adjustments updated various accounts to December 31, 2015. In the other four adjustments, the utility agreed to limit rate case expense to the actual amount incurred as of April 30, 2016, and amortize those costs over the first two years' rates from this case are in effect. Legal expenses incurred after April 30, 2016, will be included in a subsequent OG&E rate case. The utility agreed to remove legal fees paid in this case on behalf of the OG&E Shareholders and to remove costs associated with the Supplemental Executive Retirement Plan ("SERP"). Additionally, the utility agreed to credit ratepayers with a gain realized from the sale and repurchase of a turbine rotor for the McClain generating plant. Here the utility essentially "changed its place in line" on a purchase by allowing another utility that was experiencing an emergency to take delivery of the rotor OG&E had on order. The subsequent transaction was listed as a sale and repurchase of the rotor. OG&E proposes to amortize the gain as $32,083 per year for 30 years, the depreciation life of the rotor, while the AG and the Oklahoma Industrial Energy Consumers ("OIEC") suggest it be amortized as a credit of $591,808 per year over two years.

For a summary of the various parties' position on financial issues see the Appendix C. This summary is based on the proposed orders filed by OG&E and six other parties. The Federal Executive Agencies ("FEA") addressed many of the issues in testimony, but chose to limit its recommendation to depreciation expense, which varied considerably from other parties, and to rate of return ("ROR"). The Citizen Potawatomi Nation ("CPN") did not list specific adjustments but did support the ROR recommended by the OIEC, which filed a joint recommendation with Oklahoma Energy Results, LLC ("OER").

All participating parties ("Stipulating Parties") with the exception of OG&E and the OG&E Shareholders signed *a Joint Stipulation and Settlement Agreement As To Certain Rate Design, Cost of Service and Fuel Adjustment Issues*. Two days later on May 25, 2016, OG&E filed a response to the Joint Stipulation. The Stipulating Parties put on live rebuttal testimony as to what parts of the OG&E revision they would accept. Left unresolved was the customer

charge. OG&E had proposed to increase the monthly residential customer charge to $26.54 and to increase the commercial customer charge to $48.50 per month, while the Stipulating Parties recommended it be kept at the current level of $13 per month for residential customers and $24.70 for commercial customers. OG&E proposed a compromise at $20 for residential and $30 for commercial excluding raises to public schools, oil and gas and municipal pumping customers. The Company had proposed to reduce the service initiation fee from $25 to $22.50. The Stipulating Parties wanted it reduced to $17.50. Additionally, the Oklahoma Hospital Association ("OHA") had proposed a new rider moving hospitals immediately to cost-of-service and treating adjoining campuses owned by the same entity as a single customer. OG&E recommended the proposed rider not be implemented.

II. INTRODUCTION

The original application involves $146.5 million dollars consisting of an alleged $92.5 million dollar revenue deficiency and fifty-four million dollars in new revenue since the 2012 rate case. To offset the revenue deficiency, OG&E sought a $92.5 million dollar rate increase representing an eight percent increase in base rates, although the bill impact for average residential customer bill would only be 4.9 percent, because the rate increase request, if fully granted, would be offset by $55.1 million dollars from over-recovery on the Fuel Adjustment Clause ("FAC") caused by drops in the wholesale price of fuel last winter. (Tr. p. 215.) Customer bill adjustments for the FAC problem will occur through reset of the FAC factor and a monthly credit starting thirty days or less after final order in this cause and continuing up to twelve months. In any event, during the evidentiary hearing, OG&E agreed to adjustments to its proposed revenue requirement which reduced the alleged revenue deficiency to $85.6 million dollars. After that reduction, the central dispute is whether the Commission should grant either a rate increase or a rate decrease. As discussed later in this report, several Interveners contend that there is actually a decrease in the revenue requirement, thus requiring a rate decrease.

OG&E is an investor-owned public utility with plant, property and other assets dedicated to the generation, production, transmission, distribution and sale of electricity at wholesale and retail levels within the State of Oklahoma. OG&E serves approximately 821,000 customers within a thirty-thousand square mile service territory in Oklahoma and western Arkansas. The above-captioned cause concerns costs, rates and charges attributable to OG&E's service territory

in Oklahoma, even though some of the exhibits presented in this cause show combined amounts for Oklahoma and Arkansas.

On December 18, 2015, OG&E completed filing of its application to initiate proceedings for review of OG&E's rates, charges and services and for establishment of new permanent rates and charges, which are reasonable and just. With its application, OG&E tendered its complete Application Package as required by OAC 165:70-3-1, and then provided the Public Utility Division its Supplemental Package as required by OAC 165:70-5-20.

In its application, OG&E alleges that it is not earning sufficient operating income to produce a reasonable and just return on either its capital or the value of its plant, property and other assets dedicated to public utility service. In that regard, the Commission last set base rates by Order No. 599558, effective July 9, 2012 (2012 rate order). Since then, OG&E added $2.2 billion dollars to its rate base. Of that amount, $1.6 billion dollars went for new infrastructure for which OG&E was unable to receive recovery under the 2012 rate order. Presently, OG&E seeks for its proposed rate base a ROR on equity of 10.25% compared with 10.2% under the 2012 rate order.[1] At 5.26 percent for the average cost of debt, the resulting overall ROR, sometimes called the allowable ROR, would be 8.088% at a 53.31 percent common equity, compared with 11.7% under the algorithm used in the 2012 rate order with a similar equity ratio.

III. HEARINGS AND APPEARANCES

Administrative Law Judge Ben Jackson ("ALJ") presided over all hearings, which consisted of:

October 29, 2015– Motion for Protective Order
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

December 3, 2015 – Motion for Assessment of Costs
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

February 4, 2016 – Motion to Intervene by Citizen Potawatomi Nation
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

February 4, 2016 – Motion to Establish Notice
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

February 4, 2016 – Motion to Establish Procedural Schedule
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

[1] 10.2 percent appears on page 15 in finding 4b of Order No. 599558.

March 10, 2016 – Motion to Intervene by Sierra Club
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

March 24, 2016 – Objection to TASC's 1st Set of Data Requests
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

March 24, 2016 – Motion for Reclassification of AG Discovery Response
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

March 31, 2016 – Motion to Intervene by Federal Executive Agencies
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

April 21, 2016 – Motion to Associate Counsel for Sierra Club
in Courtroom B, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

May 3-6, 9-12, 16-19, 23-26, 2016 - Hearing on the Merits
in Courtroom 301, 2101 North Lincoln Blvd., Oklahoma City, OK 73105

The agenda for each day of hearing was properly posted according to the Oklahoma Open Meeting Act, 25 O.S. 2011 §301, *et seq*. During the hearings, the following appearances were entered for parties and interveners:

Kimber L. Shoop, Patrick D. Shore, William L. Humes, William J. Bullard, John D. Rhea, and David A. Kutik, Attorneys *representing* Oklahoma Gas and Electric Company

Judith L. Johnson, Natasha M. Scott and Patrick M. Ahern, Attorneys *representing* Public Utility Division, Oklahoma Corporation Commission

Dara M. Derryberry, Assistant Attorney General *representing* Office of the Oklahoma Attorney General

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

Ronald E. Stakem and Jack G. Clark, Jr., Attorneys *representing* OG&E Shareholders Association

Deborah R. Thompson, Attorney *representing* AARP and Oklahoma Sustainability Network ("AARP/OSN")

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

Cheryl A. Vaught, Scot A. Conner and Jon W. Laasch, Attorneys *representing* Oklahoma Energy Results, LLC

James A. Roth, Marc Edwards and Dominic D. Williams, Attorneys *representing* Alliance for Solar Choice, Oklahoma Hospital Association and Wind Coalition ("ASC/OHA/ Wind Coalition")

Thad Culley, Attorney *representing* Alliance for Solar Choice

Jacquelyn L. Dill, S. Laurie Williams and Casey Roberts, Attorneys *representing* Sierra Club

Lee W. Paden and George Wright, Attorneys *representing* Citizen Potawatomi Nation

Thomas A. Jernigan, Attorney *representing* Federal Executive Agencies

Melodie Garneau and Douglas Holsted, President and Co-chair, *representing* VOICE

IV. PUBLIC COMMENT

During this cause, the ALJ received unsworn public comments, which the ALJ made a part of the record. Those public comments include written comments filed with the Commission's Court Clerk and presentations made during the full evidentiary hearing. The formal record contains copies of the written comments identified for the record as public comment, and the record contains lists of all persons who presented public comment at the full evidentiary hearing.

V. JURISDICTION AND NOTICE

The Commission has jurisdiction of the subject matter and persons, as well as authority to issue a final order in this cause. Jurisdiction arises under Ok. Const. Art. IX, §18, *et seq.*, and 17 O.S.§151, *et seq.*, in particular 17 O.S. 2011 §§137, 152, 158.27, 251 and 284. Commission Order No. 650808, issued in this cause, set the terms of the notice. Notice was proper and given as required by law and Commission rules.

VI. RATEMAKING METHOD

Regulation is a balancing act between ratepayers and investors. The goal of utility ratemaking is to determine the total amount of revenues a company must generate from its operations in order to achieve its own objectives, while meeting the needs and objectives of its customers. In setting public utility rates, the Commission acts in its legislative capacity,[2] and the Commission is not bound by any particular theory or method of fixing rates, as ratemaking is not a matter of exact science or capable of precise mathematical calculation.[3] Major utilities like

[2] *Application of Bell Telephone Co.*, 1978 OK 19, 575 P.2d 624.
[3] *Application of Valiant Telephone Co.*, 1982 OK 159, 656 P.2d 273.

OG&E ask the Commission to consider the full spectrum of revenues and costs. For a major utility like OG&E, the Commission has historically used the cost-of-service method of ratemaking, which is the method used in this report. The cost-of-service method equates "revenue requirements" or "cost-of-service" with the total of: operating expenses, depreciation, taxes, and a ROR allowance on the utility's investment in rate base.

The total recorded or estimated amounts for operating expenses, depreciation, and taxes for the period under review, or test period, are deducted from revenues generated during the test period to determine net operating income realizable at current rates. This represents the amount available for return.

The rate base consisting of the utility's investment facilities and other assets used in supplying utility service is also determined. The required ROR is determined by analyzing the components of the capital structure to produce the composite ROR required to adequately meet the utility's capital requirements. Rate base multiplied by this composite ROR results in the required return, or net operating income.

By comparing the required return with net operating income realizable at current rates, the net-operating-income surplus or deficiency can be determined. This amount, adjusted for income tax and other factors, is then converted to a gross revenue surplus or deficiency in order to determine the required rate increase or decrease.

VII. TEST-PERIOD

Computing the test-period cost-of-service is the crux of the ratemaking process. An important factor in determining test-period cost-of-service is the selection of the test period. In selecting a test-period, the Commission has historically used an historic-average test year, which is a recent, consecutive, twelve-month period with a full year of operations. Here, OG&E selected the test year as the twelve-month period ending on June 30, 2015. But note, 17 O.S. 2011 §284 requires the Commission to give effect to known and measurable changes in revenues and costs, occurring or reasonably certain to occur within six-months after test year end. As a result, this report addresses accounts and balances through December 31, 2015.

VIII. LEGAL STANDARDS

Ok. Const. Art. IX §18 requires the Commission to set rates and charges that are reasonable and just. In that regard, the Commission has a duty to ensure that rates charged by

the utility are the lowest reasonable rates,[4] and the Commission has the power to prevent a utility from passing on to ratepayers unreasonable costs.[5] As the applicant seeking relief, OG&E has the burden of persuasion about whether its proposed rates and charges are necessary as well as reasonable and just.

IX. PROCEDURAL HISTORY

The Commission set current rates and charges by Order No. 599558, effective July 9, 2012.

Commission Order Nos. 576595, 577371 and 583894 memorialize OG&E's promises to initiate a general rate case in 2013, but on August 2, 2013, OG&E filed an application in Cause No. PUD 201300124 to propose other plans, which meant that OG&E did not file a general rate application in 2013 and that the present application is its first general rate application since base rates were set in 2012.[6] The lack of 2013 rate case means that the Commission must now consider, among other things, Smart Grid Rider costs, the Stranded Meter Regulatory Asset, the Web Portal Regulatory Asset and the Southwest Power Pool Cost Tracker ("SPPCT").

On July 28, 2015, OG&E filed its Notice of Intent, giving notice to the Commission of the Company's intent to file an Application seeking to modify rates and charges for OG&E's Oklahoma jurisdictional customers as well as seek approval of appropriate tariffs and its terms and conditions of service.

On July 29, 2015, the AG filed his Entry of Appearance for Jerry J. Sanger.

On August 4, 2015, the OG&E Shareholders filed its Entry of Appearance.

On August 6, 2015, OIEC filed its Entry of Appearance.

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

On September 18, 2015, the AG filed his Entry of Appearance for C. Eric Davis.

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

On October 14, 2015, OG&E filed a Motion for Protective Order, along with Notice of Hearing which set the Motion for Protective Order for hearing on October 22, 2015. On October 22, 2015, the Motion for Protective Order was continued by agreement of the parties to

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[4] *State v. OG&E,* 1975 OK 40 ¶20, 536 P.2d 887, 891.
[5] *Valiant Tel. Co. v. Ok. Corp. Comm.*, 1982 OK 159, 656 P.2d 273, 27.5
[6] In Cause PUD No. 201300124, OG&E failed to proceed with matter to final order, and the Commission ultimately dismissed the cause on April 13, 2016.

October 29, 2015. On October 29, 2015, the Motion for Protective Order was taken under advisement.

On October 22, 2015, Wal-Mart/Sam's filed its Entry of Appearance.

On November 24, 2015, the AG filed a Motion for Assessment of Costs, along with a Notice of Hearing which set the Motion for Assessment of Costs for hearing on December 3, 2015. On December 3, 2015, the AG's Motion for Assessment of Costs was taken under advisement.

On November 25, 2015, VOICE filed its Entry of Appearance.

On December 3, 2015, Order No. 647370, Order Granting Motion for Protective Order, was issued.

On December 7, 2015, the Transcript of Proceedings from December 3, 2015, was filed.

On December 10, 2015, OER filed its Entry of Appearance.

On December 18, 2015, OG&E filed the Application Package Volume I, the Application Package Volume 2, the Supplemental Package Volume 1 Sections A-J, the Supplemental Package Volume 2 Sections K-M, and the Supplemental Package Volume 3 Sections N-Q and Part 9.

Also on December 18, 2015, OG&E filed the Direct Testimonies of Gwin Cash, Robert B. Hevert, Jason J. Thenmadathil, Jarod Cassada, Ahmad Faruqui, John J. Spanos, Patricia Ruden, David Smith, William H. Wai, Bryan J. Scott and Donald R. Rowlett.

On December 30, 2015, the AG filed his Notice of Withdrawal as Counsel for Jerry J. Sanger.

On January 6, 2016, the Transcript of Proceedings from December 3, 2015, of Carol S. Dennis was filed.

On January 8, 2016, OG&E Shareholders filed its Response of OG&E Shareholders Association to Attorney General's Motion for Assessment of Costs, OG&E filed its Oklahoma Gas and Electric Company's Brief on the Attorney General's Motion for Assessment of Costs, the AG filed its Brief in Support of Attorney General's Motion for Assessment of Costs, and Public Service Company of Oklahoma ("PSO") filed its Limited Entry of Appearance and Brief of Public Service Company of Oklahoma.

On January 11, 2016, OG&E filed an Errata Filing.

On January 13, 2016, the PUD filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements.

On January 14, 2016, OG&E filed a Motion to Establish Procedural Schedule, along with a Notice of Hearing which set the Motion to Establish Procedural Schedule for hearing on January 21, 2016. On January 21, 2016, the Motion to Establish Procedural Schedule was continued by agreement of the parties to January 28, 2016. On January 28, 2016, the Motion to Establish Procedural Schedule was continued by agreement of the parties to February 4, 2016. On February 4, 2016, the Motion to Establish Procedural Schedule was heard and recommended.

Also on January 14, 2016, the Report of the Administrative Law Judge on the Attorney General's Motion for Expert Witness Fees was filed.

On January 21, 2016, OG&E filed a Motion to Establish Notice Requirements and Approve Form of Notice, along with a Notice of Hearing which set the Motion to Establish Notice Requirements for hearing on January 28, 2016. On January 28, 2016, the Motion to Establish Notice Requirements and Approve Form of Notice was continued by agreement of the parties to February 4, 2016. On February 4, 2016, the Motion to Establish Notice Requirements and Approve Form of Notice was heard and recommended.

On January 26, 2016, the OHA and ASC filed their Entries of Appearance.

On January 29, 2016, a Motion to Intervene by CPN was filed, along with a Notice of Hearing which set the Motion to Intervene by CPN for hearing on February 4, 2016. On February 4, 2016, the Motion to Intervene by CPN was heard and recommended.

On February 2, 2016, OG&E filed its Entry of Appearance for William L. Humes.

On February 4, 2016, OG&E filed Exhibit 1, Order No. 605734 (from Cause No. PUD 201200054), and Exhibit 2, OG&E's Proposed Changes to Order of Presentation.

On February 23, 2016, Order No. 650145, Order Granting Motion to Establish Procedural Schedule, was issued. The order set the Hearing on the Merits for May 3, 2016.

Also on February 23, 2016, Wal-Mart/Sam's filed its Major Issues List, OHA filed its Initial Major Issues List, ASC filed its Initial Major Issues List, PUD filed its Initial Major Issues List and OER filed its Major Issues List.

On February 24, 2016, the AG filed his Initial Major Issues List, OIEC filed its Major Issues List, AARP filed its Major Issues List and CPN filed its Major Issues List.

On February 25, 2016, Order No. 650254, Order Granting Motion to Intervene – Citizen Potawatomi Nation, was issued.

On March 2, 2016, OG&E filed its Objection to the Alliance for Solar Choice's 1st Set of Data Requests, along with a Notice of Hearing which set the Objection to the Alliance for Solar Choice's 1st Set of Data Requests for hearing on March 10, 2016. On March 10, 2016, OG&E's Objection to the Alliance for Solar Choice's 1st Set of Data Requests was continued by agreement of the parties to March 24, 2016. On March 24, 2016, OG&E's Objection to the Alliance for Solar Choice's 1st Set of Data Requests was withdrawn.

On March 4, 2016, Sierra Club filed its Entry of Appearance, and also filed a Motion to Intervene, along with a Notice of Hearing which set the Motion to Intervene for hearing on March 10, 2016. On March 10, 2016, Sierra Club's Motion to Intervene was heard and recommended.

On March 10, 2016, the AG filed his Entry of Appearance for Kimberly Carnley.

On March 11, 2016, FEA filed its Excusal Request of *Pro Hac Vice* Associated Counsel, and also filed a Motion for Admission *Pro Hac Vice*.

Also on March 11, 2016, OSN filed its Entry of Appearance.

On March 15, 2016, Order No. 650808, Order Granting Motion to Establish Notice Requirements and Approve Form of Notice, was issued.

Also on March 15, 2016, OG&E filed the Errata Direct Testimony of Donald R. Rowlett.

On March 17, 2016, ASC filed its Entry of Appearance and an Unopposed Motion to Associate Counsel.

Also on March 17, 2016, the Wind Coalition filed its Entry of Appearance.

Also on March 17, 2016, the AG filed his Motion to Reclassify Discovery Response.

On March 18, 2016, the FEA filed a Motion to Intervene.

On March 21, 2016, ASC filed a Notice of Hearing for the Unopposed Motion to Associate Counsel, which set the Unopposed Motion to Associate Counsel for hearing on April 1, 2016.

Also on March 21, 2016, the AG filed a Notice of Hearing for the Motion to Reclassify Discovery Response, which set the Motion to Reclassify Discovery Response for hearing on March 24, 2016. On March 24, 2016, the Motion to Reclassify Discovery Response was stricken.

Also on March 21, 2016, OER filed the Responsive Testimony and Exhibits of James R. Dauphinais, and PUD filed the Responsive Testimonies of Geoffrey Rush, Jason Chaplin, Hunter Hogan, Kathy Champion, Sharhonda Dodoo, Kiran Patel, David Garrett Part I and Part II, and Robert C. Thompson, CPA and PUD filed its Accounting Exhibit.

Also on March 21, 2016, OIEC and OER filed the Direct Testimony of Jacob Pous, the Responsive Testimony of Mark E. Garrett and the Direct Testimony and Exhibits of David C. Parcell.

Also on March 21, 2016, the AG filed the Responsive Testimony of J. Bertram Solomon, the Responsive Testimony of James W. Daniel, the Responsive Testimony and Exhibits of Kevin J. Mara, the Responsive Testimony and Exhibits of E. Cary Cook, the Responsive Testimony of Edwin C. Farrar, the Unredacted Responsive Testimony and Exhibits of Paul J. Wielgus, and the Redacted Responsive Testimony and Exhibits of Paul J. Wielgus.

On March 22, 2016, ASC filed an Amended Notice of Hearing for the Unopposed Motion to Associate Counsel, which set the Unopposed Motion to Associate Counsel for hearing on March 30, 2016. On March 30, 2016, the Unopposed Motion to Associate Counsel was heard and recommended.

On March 23, 2016, OG&E Shareholders filed its Response to the Attorney General's Motion to Reclassify Discovery Response.

On March 24, 2016, OIEC and OER filed the Errata Responsive Testimony of Jacob Pous.

Also on March 24, 2016, OG&E filed its Objection to FEA's Motion to Intervene, along with a Notice of Hearing, which set the Objection to FEA's Motion to Intervene for hearing on March 31, 2016. On March 31, 2016, the Objection to FEA's Motion to Intervene was heard and denied.

On March 25, 2016, FEA filed a Motion for Continuance and also filed its Opposition to Oklahoma Gas and Electric Company's Objection to Federal Executive Agencies' Motion to Intervene and Motion to Strike Filed Testimony and Discovery Requests.

On March 30, 2016, FEA filed a Notice of Hearing which set the Motion to Intervene for hearing on March 31, 2016. On March 31, 2016, the Motion to Intervene was heard and recommended.

On March 31, 2016, Wal-Mart/Sam's filed the Responsive Rate Design and Cost of Service Testimony and Exhibits of Steve W. Chriss, FEA filed the Responsive Testimony and Exhibits of Michael P. Gorman, CPN filed the Responsive Testimony of John A. Barrett, PUD filed the Responsive Rate Design Testimony of Kathy J. Champion, the Cost of Service Responsive Testimony of Jeremy K. Schwartz, OHA filed the Responsive Joint Testimony of John G. Athas and Kathleen A. Kelly and TASC filed the Responsive Testimony of Mark E. Garrett.

Also on March 31, 2016, OIEC and OER filed Objections of Oklahoma Industrial Energy Consumers and Oklahoma Energy Results, LLC to Oklahoma Gas and Electric Company's Sixth Set of Data Requests, along with a Notice of Hearing which set the Objections of Oklahoma Industrial Energy Consumers and Oklahoma Energy Results, LLC to Oklahoma Gas and Electric Company's Sixth Set of Data Requests for hearing on April 7, 2016. On April 7, 2016, the Objections of Oklahoma Industrial Energy Consumers and Oklahoma Energy Results, LLC to Oklahoma Gas and Electric Company's Sixth Set of Data Requests were continued by agreement of the parties to April 14, 2016. On April 14, 2016, the Objections of Oklahoma Industrial Energy Consumers and Oklahoma Energy Results, LLC to Oklahoma Gas and Electric Company's Sixth Set of Data Requests were withdrawn.

Also on March 31, 2016, OIEC and OER filed the Responsive Testimony of Mark E. Garrett, and the AG filed the Responsive Testimony and Exhibits of James W. Daniel, the Responsive Rate Design Testimony of Edwin C. Farrar, and the Responsive Testimony of Kevin J. Mara.

On April 5, 2016, the OG&E Shareholders filed its Statement of Position.

On April 6, 2016, FEA, OSN, AARP, Wind Coalition and Sierra Club filed their respective Statements of Position.

On April 8, 2016, public comments were filed, and the AG filed the Errata Responsive Testimony and Exhibits of James W. Daniel.

On April 11, 2016, a Confidentiality Agreement was filed.

Also on April 11, 2016, FEA filed the Rebuttal Testimony of Michael P. Gorman, ASC filed the Rebuttal Testimony of Mark E. Garrett, OER filed the Supplemental Testimony and Exhibits of James R. Dauphinais, and OG&E filed the Rebuttal Testimony of Robert B. Hevert, the Rebuttal Testimony of Scott Forbes, the Rebuttal Testimony of David Smith, the Rebuttal

Testimony of William H. Wai, the Rebuttal Testimony of Ahmad Faruqui, the Rebuttal Testimony of Roger D. Walkingstick, the Rebuttal Testimony of Gwin Cash, the Rebuttal Testimony of Donald R. Rowlett, the Rebuttal Testimony of Jason J. Thenmadathil, the Rebuttal Testimony of Jarod Cassada, the Rebuttal Testimony of Bryan J. Scott and the Rebuttal Testimony of John J. Spanos.

Also on April 11, 2016, the Errata for W/P's L-8.1, L-8.2, L-8.3 was filed.

Also on April 11, 2016, OIEC and OER filed the Rebuttal Testimony of Mark E. Garrett and the AG filed the Rebuttal Testimony of Edwin C. Farrar.

On April 12, 2016, OG&E filed the Publication Affidavits, confirming publication had been effected in the counties of Oklahoma, Tulsa, Grant, Alfalfa, Woods, Garfield, Woodward, Ellis, Dewey, Carter, Johnston, Bryan, Sequoyah, Cherokee and LeFlore.

On April 12, 2016, OG&E filed an Entry of Appearance for David A. Kutik and also filed an Errata Filing to the Rebuttal Testimony of Donald R. Rowlett.

On April 13, 2016, Sierra Club filed a Motion to Associate Counsel, Casey Roberts, along with a Notice of Hearing which set the Motion to Associate Counsel, Casey Roberts, for hearing on April 21, 2016. On April 21, 2016, the Motion to Associate Counsel, Casey Roberts, was heard and recommended.

Also on April 13, 2016, Sierra Club filed a Motion to Associate Counsel, Susan L. Williams, along with a Notice of Hearing which set the Motion to Associate Counsel, Susan L. Williams, for hearing on April 21, 2016. On April 21, 2016, the Motion to Associate Counsel, Susan L. Williams, was heard and recommended.

Also on April 13, 2016, OG&E filed an Errata Filing to the Rebuttal Testimony of Robert B. Hevert.

On April 22, 2016, FEA filed the Summary of Responsive Testimony and Rebuttal Testimony of Michael P. Gorman and OG&E filed the Supplemental Testimony of Donald R. Rowlett, the Testimony Summary of Roger D. Walkingstick, the Testimony Summary of Scott Forbes, the Testimony Summary of William H. Wai, the Testimony Summary of Robert B. Hevert, the Testimony Summary of Patricia Ruden, the Testimony Summary of John J. Spanos, the Testimony Summary of Jarod Cassada, the Testimony Summary of Gwin Cash, the Testimony Summary of Donald R. Rowlett, the Testimony Summary of David Smith, the Testimony Summary of Ahmad Faruqui, and the Testimony Summary of Bryan J. Scott.

Also on April 22, 2016, FEA filed the Summary of Responsive Testimony of Brian C. Andrews and the Summary of Responsive Testimony of Christopher C. Walters.

Also on April 22, 2016, OHA filed the Testimony Summary of John G. Athas and Kathleen A. Kelly, TASC filed the Summary of Responsive and Rebuttal Testimonies of Mark E. Garrett, CPN filed the Summary of Responsive Testimony of Chairman John A. Barrett and OER filed the Summary of Responsive Testimony and April 11, 2016, Supplemental Testimony of James R. Dauphinais.

Also on April 22, 2016, OG&E filed the Entry of Appearance of John D. Rhea.

Also on April 22, 2016, PUD filed the Testimony Summary of Geoffrey M. Rush, the Testimony Summary of David J. Garrett, the Summary Testimony of Jason C. Chaplin, the Summary Testimony of Kiran Patel, the Summary Responsive Testimony of Kathy Champion, the Rate Design Summary Testimony of Kathy Champion, the Cost–of-Service Summary Testimony of Jeremy K. Schwartz, the Testimony Summary of Sharhonda Dodoo, the Summary Testimony of Robert C. Thompson, CPA and the Summary Testimony of Hunter Hogan.

Also on April 22, 2016, Wal-Mart/Sam's filed the Summary of the Responsive Rate Design and Cost–of-Service Testimony and Exhibits of Steve W. Chriss, OIEC and OER filed the Summary Testimony of Mark E. Garrett on Revenue Requirement Issues, the Summary Testimony of Mark E. Garrett on Cost of Service/Rate Design Issues, the Summary Testimony of David C. Parcell, the Testimony Summary of Jacob Pous, the AG filed the Summary of the Responsive Testimonies of James W. Daniel, the Summary of Responsive Testimonies of Kevin J. Mara, the Summary of Responsive Testimony of E. Cary Cook, the Summary of Responsive Testimony of J. Bertram Solomon, the Summary of Responsive and Rebuttal Testimonies of Edwin C. Farrar, and the Summary of Responsive Testimony of Paul J. Wielgus.

On April 25, 2016, the AG filed an Amended Exhibit and Witness List, OER and OIEC filed their respective Exhibit and Witness lists, and OSN, AARP, PUD, OG&E Shareholders, OG&E, Wind Coalition, OHA, ASC and Sierra Club filed their respective Exhibit Lists.

On April 26, 2016, the Pre-hearing Conference was heard and recommended.

Also on April 26, 2016, CPN, Wal-Mart/Sam's and FEA filed their respective Exhibit Lists.

On April 27, 2016, Order No. 652121, Order Granting Unopposed Motion to Associate Counsel, was issued.

Also on April 27, 2016, FEA filed the Errata Responsive Testimony of Christopher C. Walters.

On April 28, 2016, OSN and AARP each filed an Amended Exhibit List and ASC filed a Supplemental Exhibit List.

On May 2, 2016, Public Comments were filed, and the AG filed the Errata Responsive Testimony of Edwin C. Farrar.

On May 3, 2016, this cause came on for hearing, and was continued from day to day through May 27, 2016.

On May 4, 2016, Public Comments were filed and the Transcript of Proceedings of May 3, 2016 – p.m. was filed.

Also on May 4, 2016, the Public Comments Sign-in Sheet from May 3, 2016, was filed.

On May 5, 2016, the Transcript of Proceedings from May 4, 2016, was filed.

On May 6, 2016, the Transcript of Proceedings from May 5, 2016, Afternoon Session was filed.

On May 6, 2016, Public Comments were filed.

On May 9, 2016, the Transcript of Proceedings from May 6, 2016, Morning Session was filed.

Also on May 9, 2016, the Transcript of Proceedings from May 6, 2016, was filed and the Transcript of Proceedings from May 5, 2016, Morning Session, was filed.

On May 9, 2016, the Deliberations by Commissioner Bob Anthony and filing by Scott Hempling, Esq. at Supreme Court, was filed.

On May 10, 2016, the Transcript of Proceedings from May 9, 2016, P.M. was filed, and Public Comments were filed.

On May 11, 2016, the Transcript of Proceedings from May 10, 2016, P.M. was filed and the Transcript of Proceedings from May 10, 2016, was filed.

On May 23, 2016, the Joint Stipulation and Settlement Agreement as to Certain Rate Design, Cost of Service, and Fuel Adjustment Issues was filed.

On May 25, 2016, OG&E filed its Response to Joint Stipulation and Settlement Agreement as to Certain Rate Design, Cost of Service, and Fuel Adjustment Issues.

X. SUMMARY OF THE TESTIMONY

Appendix A to this report contains a summary of the testimony, which was fully transcribed.

XI. REVENUE REQUIREMENT

A. Background

Rate development has three components: determination of the revenue requirement for the test-period, allocation of costs to customer classes based on usage patterns (cost-of-service study), and rate design to recover costs through rates and charges. The cost-of-service method of ratemaking equates "revenue requirements" or "cost-of-service" with the total of operating expenses, depreciation, taxes and a ROR allowance on the utility's investment in rate base (allowable ROR). The total recorded or estimated amounts for operating expenses, depreciation, and taxes, for the test period are deducted from revenues generated during the test-period to determine net operating income realizable at current rates. This represents the amount available for return. The revenue requirement is calculated using the following formula:

Revenue requirement = r(RB) + E +D + T

r = overall rate of return (allowable rate of return)

RB = rate base

E = operating expenses

D = Depreciation and amortization

T = taxes

In OG&E's W/P Schedule B-1, OG&E calculated its revenue requirement to be approximately $1.3 billion dollars.

B. Admitted Facts

With respect to the OG&E application and supplemental package, the ALJ deems admitted all facts and allegations that were not in dispute at the end of the full evidentiary hearing. The following focuses on the remaining facts and issues that were in dispute.

C. Allowed Return on Equity

The standard method for reaching a fair ROR involves, 1) an estimation of the capital attraction rates for each component of the utility's capital; and 2) a combination of the various costs of capital into one overall ROR according to the percentage each component bears to overall capitalization. In this ratemaking, capital attraction centers on return-on-equity ("ROE").

OG&E's 2012 rate order set ROE at 10.2 percent, based on a stipulation by the parties in that proceeding. In the present rate case, OG&E proposes to increase ROE to 10.25 percent, which is at the low end of OG&E's ROE witness Mr. Hevert recommended range of 10.25 percent to 10.75 percent. In opposition, several Interveners propose lower ROE values with final estimates ranging from 8.89 percent to 9.3 percent. Table 3 is a table summarizing the ROE positions of the parties, as well as corporate structure, cost of debt and overall ROR.

Witness	On Behalf of	Range	Recommended ROE	Reference
D. Parcell	OIEC/OER	8.85% - 9.50%	9.00%	Parcell Responsive, Pg. 3, Ln. 6-8
J.B. Solomon*	AG	6.77% - 9.64%	8.90%/9.25%	Solomon Responsive, Pg. 39, Ln. 9-16
D. Garrett	Staff	8.75% - 9.25%	9.25%	Exhibit DG 1-2
C. Walters	FEA	9.00% - 9.60%	9.30%	Walters Responsive, Pg. 4, Ln. 4-6
R. Hevert**	OG&E	10.25% - 10.75%	10.25%/10.50%	Hevert Direct, Pg. 4, Ln. 14-19

*Mr. Solomon recommends OG&E be awarded a 9.25% ROE with a capital structure of 50% equity / 50% debt. If the Commission adopts OG&E's requested capital structure, he recommends an 8.9% ROE.

**Mr. Hevert recommends a ROE of 10.5%. OG&E is requesting a ROE of 10.25%.

The ALJ submits that the table shows a wide range of proposed ROEs, because setting ROE is not an exact science. Historically, regulatory proceedings have used two approaches: the Comparable Earnings Approach and Market Analysis. Due to varying data sources, business cycles, investor biases, and other factors, these two approaches can produce different results that are dependent on variable time periods. Additionally, the two approaches are theoretically different. In the Comparable Earnings Approach, the analyst derives the utility's cost of equity from published data on the achieved returns that firms actually earn on their investments. In Market Analysis, the analyst tries to calculate the cost of equity capital using data from the securities markets. Market Analysis can be broken down into two different types of analysis, namely Discounted Cash Flow ("DCF") and the Capital Asset Pricing Model ("CAPM").

Here, each expert witness generated a range or "zone of reasonableness" by computing ROEs for a proxy group of companies selected by that expert. Each member of the proxy group is financially similar to OG&E, and with one exception, the proxy groups were similar to Mr. Hevert's proxy group seen in Figure 1 of Hevert's Direct Testimony p. 16. The exception

came from AG witness Mr. Solomon who had only ten companies in his proxy group compared with Mr. Hevert's nineteen. However, the ALJ finds that the differences in selected companies did not affect the ALJ's decision on ROE. In any event, the ROE witnesses calculated ROEs for each company in their proxy groups using accepted methods. Although the ROE witnesses did not all use or rely on either the same methods or inputs, the list of accepted methods for the ROE witnesses as a group includes a standard list of techniques, namely, constant growth rate and multi-stage discounted cash flow models, earnings/price ratios, capital asset pricing model, bond risk premium analysis, and comparative earnings models.

The dispute here concerns whether ROE should be OG&E's 10.25 percent or one of the opponents' estimates at 9.0, 9.25 or 9.30 percent. The legal standard for selecting an ROE value comes from *The Hope and Bluefield Decisions,* which created the End Result Doctrine where the reasonableness of the result controls instead of the choice of method.

The final estimates for all ROE witnesses as a group differ from 0.95 percent to 1.25 percent. The dispute arises from the fact that small differences in ROE seriously impact the revenue requirement due to OG&E's $4.2 billion dollar rate base. The final ROE estimates polarized between OG&E at 10.25 percent and the opponents with final estimates between 9.0 percent and 9.3 percent. The AG and FEA witnesses picked mid-points in their proxy ranges. The other ROE witnesses chose final estimates reflecting adjustments for informed judgment.

Looking at the ROE witnesses as a group, ranges for certain proxy groups overlap under certain methods of calculation. OIEC/OER's witness Mr. Parcell, whose final estimate was 9.0 percent, had a range of 8.89 to 9.5 percent for his Discounted Cash Flow and a range of 9.0 to 10.0 percent for the Comparable Earnings Model. (Parcell, Responsive Testimony, p.5 ln 1-11.) FEA's witness Mr. Walters recommended 9.3 percent, but his DCF analyses, CAPM and Risk Premium Analysis produced a range between 9.0 to 9.6 percent. OG&E's witness Mr. Hevert's constant growth rate DCF analysis produced mean results between 9.30 and 9.39 as seen on Table 4 taken from Mr. Hevert's Table 2 in Direct Testimony page 21.

Table 4

	Mean Low	Mean	Mean High
30-Day Average	8.59%	9.30%	9.98%
90-Day Average	8.71%	9.42%	10.10%
180-Day Average	8.68%	9.39%	10.06%

However, Mr. Hevert's multi-stage DCF analysis produced a range of 9.44 to 9.96 percent seen in Table 5 below taken from Mr. Hevert's Direct Testimony Table 5 at page 27.

Table 5

	Mean Low	Mean	Mean High
30-Day Average	9.44%	9.63%	9.81%
90-Day Average	9.57%	9.77%	9.96%
180-Day Average	9.54%	9.73%	9.92%

As a result, Mr. Hevert's DCF analyses are between 9.30 percent and 9.96 percent, even though he recommended an ROE between 10.25 percent and 10.75 percent. For the ALJ, the ROE studies on both sides overlap on the upper end at ten percent and for the lower end, overlap starts at 9.30 percent, which creates a range between 9.30 percent and ten percent.

Some may argue that the ALJ should pick an expert's opinion and not set ROE independently based on a mix of evidence from different models. However, the ALJ views his assignment as one where the ALJ must identify appropriate benchmarks for ROE even if not adopted by a particular witness The ALJ's approach comes from direct testimony by Mr. Hevert where he states that the cost of equity is not directly observable but must be estimated from quantitative and qualitative information. Although a number of empirical models have been established for that purpose, all are subject to limiting assumptions or other constraints. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and therefore rely on multiple analytic approaches. No individual model is more reliable than all others under all market conditions, and equity analysts and investors tend to use multiple approaches. (Hevert, Direct Testimony p. 17, ln. 2-11.)

The ALJ observes that for many years, allowed ROE determinations were often based on constant growth rate DCF models, due to the economic stability of the electric utility industry. As an example, the Federal Energy Regulatory Commission ("FERC") narrowly focused on constant growth rate DCF analysis until 2014, when FERC adopted a multi-stage DCF model,

adding consideration of investor expectations for long-term growth.[7] Currently, the FERC allows other methods like the non-DCF models used in this cause.[8]

Regardless of the forum, the fundamental test of any ROE model is reasonableness and economic logic. A major objective for any review of reasonableness is to exclude outlier ROE estimates. As a result, the Commission should recognize that different models produce different results, but the Commission must consider what the various models point to.

One approach used by OG&E's witness Mr. Hevert was to revise market assumptions underlying his opponents' analyses. During rebuttal, Mr. Hevert adjusted some factors in opposing ROE witnesses' analyses resulting in ROE averages between 9.78% and 9.83%, which puts them at the low end of Mr. Hevert's ranges for vertically integrated companies. (Hevert Rebuttal, p. 146, ln. 9 through p. 147, ln. 2 and Table 12.) Table 6 (Hevert Table 12) shows how he revised and averaged his opponents' models.

Table 6 (Hevert Table 12)

REVISION	RESULT
Mr. Garrett's Analyses:	
Revised CAPM Estimate	10.05%
Revised DCF Estimate	9.60%
Average	9.83%
Mr. Walters' Analyses:	
DCF Estimate (Consensus Growth Rates Only)	9.23%
CAPM Estimate (8.00 percent Market Risk Premium)	9.64%
Revised Risk Premium Estimate	10.53%
Average	9.80%
Mr. Parcell's Analyses:	
DCF Estimate (First Call EPS Growth)	9.10%
Revised CAPM Estimate	10.45%
Average	9.78%

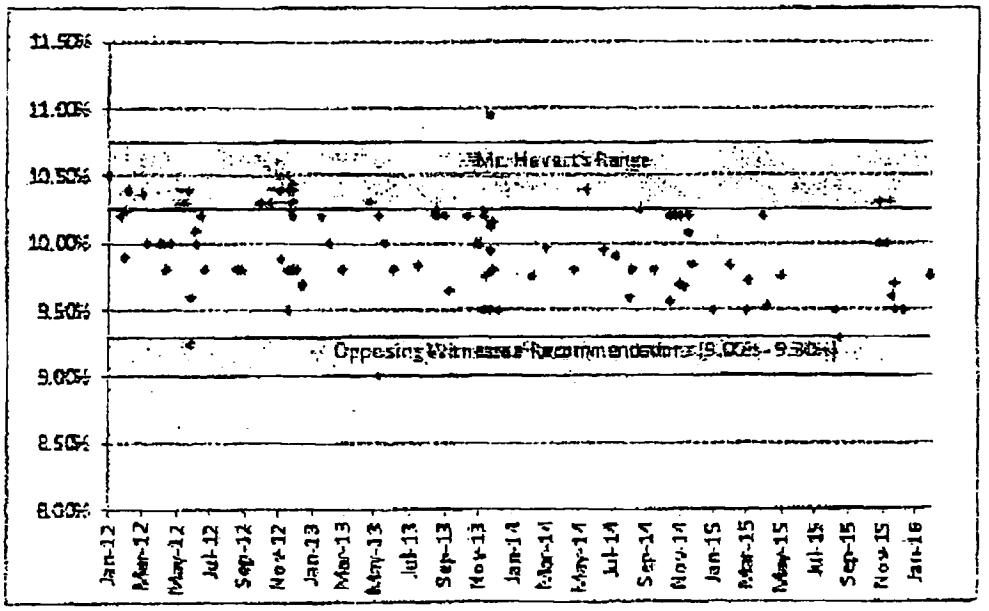
[7] FERC Opinion 531 series.
[8] *Id.*

Mr. Hevert used his Table 12 to argue that OG&E's allowed ROE should be above ten percent based on revised CAPM and Risk Premium Analyses. However, Mr. Hevert's Table 12 also shows that his adjustments produce an average ROE between 9.78 percent and 9.83 percent.

To test the reasonableness of a range of 9.78-9.83 percent, the ALJ looked for possible benchmarks elsewhere. In Mr. Hevert's Rebuttal Testimony p. 11 ln 14, Mr. Hevert presented a chart (Figure 1) showing allowed ROEs since 2012.

Figure 1

Chart 3: Authorized Returns and ROE Recommendations



Mr. Hevert apparently started with 2012, because it injects into the mix a lot of ROEs at or above his 10.25 percent. Trial Exhibit No.41, a case history from Mr. Hevert's work papers, shows allowed ROEs going back to 1979 and that during the last ten years, allowed ROEs were generally above ten percent until 2015, when the national average allowed ROE for the calendar year fell to 9.85 percent. Along that line, Trial Exhibit Nos. 20-22, 61 and 63 show recent allowed ROEs in 2015 orders from Oklahoma's neighboring States, namely, Kansas, Missouri and Texas. In those neighboring states, 2015 ROEs were 9.3, 9.5, 9.53, 9.65 and 9.70 percent, of which the 9.70 from Texas is the most recent order dated December 18, 2015. On a national level, only one allowed ROE in 2015 was for FEA's final recommendation of a 9.30, while the average ROE of the thirty-eight 2015 cases was 9.84-9.85 percent (Hevert Rebuttal Testimony p.

12). On the national level, only twelve of the thirty-eight 2015 cases had allowed ROEs of ten percent or higher.

With respect to evidence of later ROEs above ten percent, the ALJ did not admit into evidence Trial Exhibit No. 23, which is a graph showing a national average allowed ROE of 10.26 percent during the first quarter of 2016. The ALJ rejected the exhibit, because OG&E failed to provide copies of Trial Exhibit No. 23 to the other parties by the document exchange deadline. The ALJ finds that the exhibit is a publication that was readily available for document exchange and that failure to timely exchange the document warrants its exclusion to avoid surprise or delay at trial. Nonetheless, OG&E contends that the Commission should admit the exhibit, because it reflects a change in knowledge and knowledge of conditions. However, the ALJ determined that he did not need to stop the hearing to allow the parties additional time to review Trial Exhibit No. 23. The ALJ notes that the testimony about the ROE uptick seen on Exhibit No. 23, during the first quarter 2016, and that testimony was sufficient to establish that the uptick occurred, but the document itself does not establish any more than that. The uptick does not establish a sustained, upward trend in allowed ROE in 2016. There is no way to evaluate from the graph any ROE without knowing the business model, capital structure and financial risks of the companies involved, as well as the rate philosophy of the regulatory decision-makers involved.

To support an upward trend in ROE values, Mr. Hevert considered a variety of other factors, including capital market conditions, the risks associated with environmental compliance plans and significant capital expenditures, flotation costs and the effect of OG&E's rate mechanisms relative to its risk profile. (Testimony Summary of Hevert, p. 1.) However, the ALJ finds that Mr. Hevert understates market problems and overstates risks to investors. To begin with, the ALJ disagrees with Mr. Hevert's contention that current market conditions reflect investor expectation of higher interest rates and allowed ROEs above ten percent. Mr. Hevert admits that the national economy is volatile, but he discounts recent economic indicators showing that since the start of the recession in 2008-2009, the economic recovery is meager at best. In his multi-stage DCF model, Mr. Hevert used a long-term growth rate of 5.22 percent based on a Gross Domestic Product ("GDP") of 3.25 percent from 1929 through 2014. (Hevert, Direct testimony p. 26, ln 2-9.) However, the ALJ observes that over the past decade, the growth rate of real GDP per person averaged just 0.44 percent per year compared with the historical

norm of 2.0 percent and that during the evidentiary hearing in this cause, real GDP fluctuated but never reached Mr. Hevert's 3.25 percent.

Table 7

Second Quarter 2015	2.6
Third Quarter 2015	2.0
Fourth Quarter 2015	0.9
First Quarter 2016	0.8
Second Quarter 2016	1.4
Third Quarter 2016	3.1

Mr. Hevert and OIEC/OER's witness Mr. Parcell also disagreed over what the Federal Funds Rate and Treasury Yield Curves actually show about the health of the economy. Mr. Hevert is sanguine about the economy, but the ALJ agrees with Mr. Parcell, that the Federal Funds Rate and Treasury Yield Curves regardless of differences between twenty- and thirty-year notes show a consistent trend in low interest rates despite occasional spikes on the graphs.

In any event, FEA's witness Mr. Walters testified about other distortions in Mr. Hevert's analyses. The ALJ makes the following findings about the FEA testimony: Mr. Hevert's CAPM analyses are overstated, because he used an inflated risk market premium. Mr. Hevert's market risk premiums are based on projected DCF returns on the S&P 500 which contains growth rates that are excessive and unsustainable. By overstating the market growth rates, Mr. Hevert overstates his market DCF return and thus his market risk premium. With respect to Mr. Hevert's Risk Premium Analysis, he assumes a simple inverse relationship between equity risk premiums and interest rates, but that simple inverse relationship is not based on either academic research or industry practice. To the contrary, the relationship between equity premiums and interest rates is driven by changes in expected risk outlooks for equity securities versus debt securities. While interest rate changes are a component of the total risk assessment, they are only a factor in describing current equity risk premiums.

Moving to another argument, Mr. Hevert further contends that investors need higher ROEs because of risks associated with utility regulatory mechanisms and environmental compliance programs. The ALJ finds that Mr. Hevert overstates his concerns and that OG&E may be in a better position that its competitors. In terms of capital structure, OG&E has

common equity at fifty-three percent compared with a national average at fifty-percent. For revenue, forty-three percent of OG&E revenues come from riders (TR. 5/9/16 a.m. at p. 96), including one third of OG&E's revenues come from the fuel and purchased power rider ("FAC"). (Tr. 5/9/16 a.m. at p. 96.) In that regard, there is no regulatory lag with an FAC. Next, in Cause No. PUD 201600059, OG&E successfully applied to the Commission for dry scrubbers to extend lifespan of two coal fired units, even though SPP had 4,800 megawatts of surplus capacity. Meanwhile, in January, 2016, OG&E had to shut-in certain coal fired units because of competition from cheap natural gas. During that period, OG&E got cheap electricity from SPP's Integrated Marketplace and still OG&E got to recover through retail rates capital costs on the shut-in units.

From a different angle, Mr. Hevert further contends that future federal environmental regulations could make certain OG&E coal plants uneconomic to either operate or upgrade. OIEC/OER's witness Mr. Parcell contends that such risks are already reflected in the stock price and incorporated in the DCF analysis. Furthermore, Mr. Hevert forgets about the stranded cost argument that would arise in ratemaking from premature abandonment of any facility previously declared by Commission order to be used and useful to ratepayers. Therefore, the ALJ sees no reason to boost ROE because of environmental regulatory risk.

Mr. Hevert expressed further concern about floatation costs, which are incurred by a publicly traded company when it issues new securities and includes expenses such as underwriting fees, legal fees and registration fees. Flotation costs can make a project either less attractive or unattractive to investors where the net present value of the project with flotation costs is zero or negative. In any event, Mr. Hevert calculated the cost of float to be only twelve basis points. (Hevert, Direct Testimony p. 45, ln 18-22.) Furthermore, he did not recommend a quantitative adjustment to ROE for floatation expense. (Hevert, Direct Testimony p. 46, ln 3-5.)

For the ALJ, the floatation cost problem here is three-fold: Since we do not have a major new project to finance through this ratemaking, the evidence failed to provide the full details used to calculate the cost of float for new equity. At a minimum, one would need to know principle, the required return, and investment banker's fees. Next, we cannot determine whether the utility can account for floatation costs by increasing the discount rate. Furthermore, the models used to estimate ROE assume no "friction" or transaction costs, because those costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of

the CAPM and Bond Yield Plus Risk premium model). (Hevert, Direct Testimony p. 44, ln. 17-21.) Therefore, the ALJ did not see a need to consider flotation costs.

After considering all of the ROE evidence, the ALJ reached the following conclusions: appropriate benchmarks point to 9.87 percent for the allowed ROE, with a "range of reasonableness" between 9.7 percent and 10.0 percent. The upper end of the ALJ's ROE range comes from a combination of the upper end of OIEC/OER's witness Mr. Parcell's comparable earnings model (ten percent) and the upper end of Mr. Hevert's multi-stage DCF model (9.96 percent). The low end of the ALJ's range stems from Trial Exhibit No. 61, which is a 2015 rate order from the Texas PUC for Southwestern Public Service Company ("SPS"), a subsidiary of Excel Energy and an interstate, integrated electric utility, serving 391,000 customers over a 50,000 square mile service territory. At paragraph 76A, p. 24 of the Texas order, the Texas PUC set for SPS an allowed ROE of 9.7 percent and an allowable ROR at 7.88 percent. The ALJ views those rates as regional benchmarks for investors, because all electric utilities like OG&E and SPS, who sell securities on major stock exchanges, compete for investor funds. To match SPS's overall ROR, OG&E at its current capital structure and average cost of debt, would need an allowed ROE of 9.868 percent.[9] If the Commission set a lower ROE, investor funds may move to Texas, because the allowable ROR in the Texas rate order allows SPS to earn higher earnings per share. The ALJ realizes that the Commission has constitutional and statutory duties to set the lowest reasonable rates reflecting the lowest reasonable cost-for-service, but the Commission must balance that obligation with the Commission's duty to the utility to set rates and charges that reasonably allow the utility to attract investor capital. Proponents of a low OG&E ROE, *i.e.* an ROE between 9.0 percent and 9.3 percent, failed to show that investors would be attracted to investing for a lower allowable rates of return than 7.88 percent as seen in the Texas rate order. Obviously, both sides of the ROE dispute can point to allowed ROEs elsewhere that are above or below 9.87 percent for an allowed ROE, but at the end of day, the Commission has to decide how much of a drop in ROE is in the best interests of all concerned. The proponents of a lower ROE contend that the Commission should lower ROE between 8.9 percent and 9.3 percent. The ALJ finds that such a drop is extreme in the current economy. As a result, the ALJ used the principle of regulatory gradualism and set ROE at 9.87 percent, based on

[9] ROE = (7.88 Texas ROR – (.467 OG&E debt in capital structure x 5.62 OG&E average interest on debt)) /.533 OGE equity ratio = 9.868 percent.

the regional benchmark. On the other side, the ALJ notes that one needs to consider the impact of capital structure and other factors if you are looking for a higher ROE based on Trial Exhibit Number 3. That is to say that you cannot evaluate a published quarterly graph of new allowed ROEs without knowing factors such as the capital structures of utilities on the graph, their business models, credit ratings and the financial risks associated with those companies.

D. Capital Structure and Cost of Debt

"Capital structure" refers to the way a firm finances its overall operations through external financing. If a firm is financed entirely through equity, its cost of capital equals the return required by investors on the company stock, and one can use the CAPM to estimate that return. However, very few companies are financed entirely by equity. Instead, they are financed by a mix of securities, like bonds and stocks, each with its own cost of capital. When there is a mix of securities, an investor's expected return should equate with the weighted after-tax cost of the debt financing plus the cost of the equity financing, where the weights are the fractions of debt and equity in the firm's capital structure. However, for ratemaking purposes, the Commission takes a different approach. The Commission sets an overall ROR on rate base, sometimes called the allowable ROR. The Commission allows the company to earn that return, but the Commission does not guarantee such a return. An algorithm can determine ROR like the stipulated one in the 2012 rate order, or the Commission can base ROR on the Commission's version of a weighted average cost of capital ("WACC"). The Commission's WACC is based on the sum of two products: The first product is ROE multiplied by the percentage of equity in the capital structure, and the second product is the average interest rate for company debt multiplied by the percentage of debt in the capital structure.

The dispute here is whether the Commission should impute a capital structure to avoid or minimize an alleged unnecessary premium paid by ratepayers on major capital projects. The issue of an alleged premium arises from the fact that debt is much less expensive than equity. OG&E generally pays dividends quarterly totaling ten percent annually. According to OG&E's Schedule F-1, OG&E pays an average of 5.62 percent on debt, which consists of pollution bonds and senior notes. However, at OG&E's current Moody bond rating (A-1), OG&E can borrow money at 3.87 percent. (PUD's witness D. Garrett Resp. Testimony p. 79, ln 3-11.) The issue, therefore, is whether OG&E pays too much for equity financing, especially considering that it is paid with post-tax dollars. None of the expert witnesses suggest that OG&E can or should either

refinance debt or buy back stock. Instead, opponents of OG&E's proposed 8.088 percent ROR ask the Commission to impute a lower common equity ratio. The current ratio is 53.31 percent equity and 46.69 percent long term debt. Opponents of an ROR at 8.088 percent want to change the balance between debt and equity to a fifty-fifty split, equal to the current national average for regulated electric utilities. Based on the ALJ's recommendations of 9.87 percent ROE and a ROR of 7.88 percent, just changing the percentages to fifty percent would lower ROR to 7.745 percent, which would defeat the purpose of setting ROR based on a regional benchmark, in this case, the Texas PUC 2015 order for SPS. The ALJ submits that to achieve the ROR regional benchmark with a fifty-fifty capital structure would require an increase in ROE to 10.14 percent.[10]

OG&E's witness Mr. Hevert recommended that the Commission adopt the current capital structure for OG&E, namely 53.31 percent common equity and 46.69 percent long-term debt. According to Mr. Hevert, OG&E's common equity ratio of 53.31 percent is within the range of 47.11 percent to 65.05 percent for common equity within Mr. Hevert's proxy group. (Hevert Direct Test. P. 55, ln 17-19.) OG&E's current common equity ratio also corresponds with an average of 52.85 percent for common equity within Mr. Hevert's proxy group during the last eight fiscal quarters. (Hevert Direct Testimony. p. 55, ln 5-11.) In opposition, OIEC/OER's witness Mr. Parcell showed that the national average common equity ratio for a regulated electric utility was forty-nine percent to fifty percent in 2015. (Parcell Surrebuttal, 5/9/16 a.m. Tr. Pp. 28-29.) PUD witness D. Garrett also recommends lower figures, which ranged from forty percent to forty-eight percent for common equity. (D. Garrett, Resp. Test. p. 89, ln 11-12 and p. 90, ln 4-12.) The low end of D. Garrett's range is based on calculation of an ideal capital structure, but Garrett did not have market data showing that such a ratio would attract investment capital to OG&E.

In response, the ALJ observes the following. The Commission's WACC concept is not based on the true cost of debt service. Tax deductions for debt reduce the cost of debt, so that the actual average interest rate is much lower than 5.62 percent. Next, if you increase OG&E's debt, investors theoretically may want a higher ROR because of higher risk, but neither truing up interest nor increasing debt is the crux of the problem. The ALJ previously established that OG&E needs a minimum ROE of 9.87 percent and a minimum ROR of 7.88 percent. If you

[10] ROE=(7.88 Texas ROR- (5.62 average debt x .5))/.5=10.14.

reduce the percentage of equity by 3.31 percent, i.e., a drop from 53.31 percent to fifty percent equity, ROR drops to 7.745 percent, meaning that OG&E no longer has a competitive ROR attractive to investors. Here, cost of existing major projects is a settled issue since no one wants to refinance the debt or buy back stock. Therefore, percentage of debt is a settled issue. As a result, the ALJ recommends staying with the status quo for capital structure.

E. Overall Rate of Return

As shown above, the ALJ found that the allowed ROE should be 9.87 percent and that the percentage of equity in capital structure should be the current 53.31 percent and that the cost of debt should be 5.62 percent with 46.69 percent debt in capital structure. Based on his prior findings in this report, ALJ finds that the reasonable and just ROR should be 7.88 percent, corresponding to what the Texas PUC granted SPS in 2015, compared with an allowable ROR of 8.088 percent requested by OG&E in this cause.

F. Rate Base

1. Background

OG&E's proposed rate base is the sum of lines one through sixteen on OG&E's amended Schedule 1 in Section B of OG&E's Supplemental Package Volume One. That proposed rate base consists of the sum of the net plant, other rate base investments and rate base additions and reductions. "Net Plant" is the sum of lines one through four of the foregoing schedule and consists of plant in service, construction work in progress, plant held for future use, and less accumulated depreciation.

2. Plant in Service

OG&E agreed to PUD's adjustments to OG&E's *pro forma* total for plant in service. The result was $9,631,284,933 dollars for OG&E's plant in Oklahoma, which includes balances through the end of the six-month post-test year period. Only OER's witness Mr. Dauphinais objected to the foregoing total, and his objection ultimately only involved the addition of a transmission line from Woodward to Thistle. In that regard, Mr. Dauphinais contends that the change in end points from Comanche County, Kansas, to the Thistle substation was unnecessary. (Tr. P.M. 5/19/2016 p. 1w-104, ln. 13-21). The ALJ finds that the change in route was necessary as well as reasonable and just in cost. OG&E witness Mr. Rowlett testified that the major driver for the change in end points was due to minimize impact on the habitat of the Lesser Prairie Chicken. (Rowlett Supplemental, p. 2, ln. 23 through p. 3, ln. 1.) The Southwest Power

Pool ("SPP") which is the regional transmission operator thoroughly vetted the project and properly approved the line, which is also included in OG&E's FERC approved rates, and no evidence was produced showing that the costs of those projects were challenged during the FERC ratemaking process. Mr. Dauphinais failed to present evidence showing that the actual costs of the line were unreasonable. As a result, the Commission should find that the Woodward-to-Thistle transmission line was necessary and reasonable in cost, and the Commission should find that the *pro forma* plant in service for OG&E in Oklahoma should be $9,631,284,933 dollars.

3. Holding Company Assets

OG&E includes OGE Energy Corp. ("Holding Company") Assets as a part of plant in service. A percentage of these assets are devoted to non-utility activity and should therefore be excluded from rate base. (*See* Thenmadathil Direct at p. 4.) This results in a decrease to plant in service of $28,516,476, which was later adjusted to the end of the six-month post-test year period. No party opposed this adjustment. The ALJ finds that this adjustment reflects the Company's allocation of the Holding Company assets to non-utility activity and that the Commission should adopt the Company's adjustment which decreases rate base $27,692,872 (as adjusted to the end of the *pro forma* test year period).

4. Construction Work in Progress

Although Net Plant includes construction work in progress, there were no balances for construction work in progress, but OG&E included a schedule for expenses in Construction Work in Progress ("CWIP") accounts maintained for accounting purposes.

5. Plant Held for Future Use

OG&E proposes changes to rate base for property held for future use. Taken from the OG&E's W/P C-13, Table 7 shows the properties, acquisition dates and acquisition costs.

Table 7

Section C - Plant In Service
W/P C-13

OKLAHOMA GAS AND ELECTRIC COMPANY
PROPERTY HELD FOR FUTURE USE
TEST YEAR ENDING 6/30/15
CAUSE NO. PUD 201500273

Line No.	Description	Amount	Account	Date of Acquisition/ Completion	In Service Date	Use
1.	LAND	5,543	105	1988	2017	Anderson Road Sub
2.	LAND	8,824	105	1986	2018	Mountainburg Sub
3.	EASEMENT	375	105	1986	2018	Mountainburg Sub
4.	LAND	5,900	105	1986	2018	Canadian River Sub
5.	LAND	16,928	105	1987	2020	Ridgeview Sub
6.	LAND	5,231	105	1987	2018	S E 134th Sub
7.	LAND	10,168	105	1987	2020	Sooner Road Sub
8.	LAND	3,259	105	1988	2018	Lovell Sub
9.	LAND	9,582	105	1989	2020	Banner Sub
10.	LAND	10,304	105	1970	2016	Akins Sub
11.	LAND	18,589	105	1970	2020	Post Road Sub
12.	LAND	4,308	105	1971	2020	State Center Sub
13.	LAND	6,336	105	1971	2022	Diamond Sub
14.	LAND	7,273	105	1972	2018	Purdue Sub
15.	LAND	11,372	105	1972	2018	Springdale Sub
16.	LAND	2,632	105	1973	2020	Sacred Heart Sub
17.	LAND	6,237	105	1973	2020	Taft Sub
18.	LAND	17,586	105	1973	2020	Wheatland Sub
19.	LAND	12,051	105	1974	2020	Saran Sub
20.	LAND	26,181	105	1974	2016	Rancho Sub
21.	LAND	22,356	105	1974	2018	SW 29th Street Sub
22.	LAND	30,187	105	1974	2022	Jaycee Sub
23.	LAND	140,078	105	1978	2025	Garrison Sub
24.	EASEMENT	54,658	105	1983	2016	345 KV H-Frame - W. Ft. Smith Loop
25.	EASEMENT	164,719	106	1963 & 1969	2016	345 KV Tower - W. Ft. Smith Loop
26.	LAND	38,861	105	1984	2016	Breckenridge Sub
27.	LAND	5,282	106	1987	2020	Midwest Blvd Sub
28.	LAND	10,488	105	1987	2018	Newcastle Sub
29.	EASEMENT	37,002	105	1989	2018	161 KV H-Frame - W. Ft. Smith Loop
30.	LAND	68,634	105	2002	2018	Shady Grove Sub
31.	LAND	102,619	105	2002	2018	Sahoma Lake Sub
32.	EASEMENT	149,208	105	2004	2020	138 KV Piedmont-Haymaker
33.	EASEMENT	62,098	105	2005	2016	138 KV McClain-Eastywine
34.	LAND	362,717	105	2006	2018	Central Sub
35.	LAND	138,027	105	2007	2020	Yukon Sub
36.	EASEMENT	38,210	105	2007	2016	Oil Sands Sub
37.	EASEMENT	7,643	105	2007	2018	Racer Sub
38.	LAND	158,987	105	2009	2016	Matthewson Sub
39.	LAND	440,308	105	2010	2016	SW 9th Street Sub
40.	LAND	295,904	105	2014	2018	Jones Sub
	Total	$ 2,510,084 *				

Schedule B-2

* See W/P B 3-11 for amounts included in Rate Base.

During the trial, OG&E agreed to remove from rate base properties acquired before 2005.[11] That reduced the total to $1,497,777, leaving $1,276,393 at issue. In that regard, PUD supported OG&E's final number for plant held for future use. However, the AG and OIEC/OER oppose adding any of the $1,276,393 to rate base. They contend that the undeveloped properties were not used or useful to ratepayers for the provisioning of electricity service. In response, the ALJ makes the following findings: The Commission may add undeveloped property to rate base where there is a definite, near term plan to use the property as part of plant in service. *Southwestern Public Service Company v. State*, 1981 OK 136, and 637 P.2d 92, 98 (1981); *The Regulation of Public Utilities: Theory and Practice* by Charles F. Phillips, Jr., pp. 334-35 (Public Utility Reports, Inc. 1988). Where a transmission and distribution system is capable of expansion, the prudent operator should acquire property to accommodate system growth and avoid higher acquisition costs caused by escalating real estate prices. OG&E showed that it had a definite, near term plan, and properly excluded speculative property represented by any land or easement, held by OG&E more than ten years. As a result, the Commission should find that rate base should contain $1,276.393 dollars for land held for future use.

6. Accumulated Depreciation

OG&E accepted the proposal of PUD, AG and OIEC to reduce rate base for the actual accumulated depreciation balances as of December 31, 2015, which was $3,640,581,266. (Thompson Responsive, p. 17, ln. 11-14.) The ALJ finds that the accumulated depreciation balance is directly associated with the plant assets that will provide service and benefits when new rates will take effect. Therefore, the ALJ finds that the Commission should order reduction in rate base for the actual accumulated depreciation balances as of December 31, 2015, and said reduction to rate base should be $3,640,581,266 dollars.

7. Net Utility Plant

Based on the foregoing deductions from gross utility plant, the amount for net utility plant is $4,972,771,292 dollars.

Plant-in-service	$8,640,592,641
Holding Company Assets	$(28,516,476)
Construction Work-in-Progress	$ -

[11] Thenmadathil, Direct Testimony pg 7 ln 2-5.

Plant held for future use	$1,276,393
Accumulated Depreciation	$(3,640,581,266)
Net Plant	$4,972,771,292

8. Other Rate Base Investments

a. Cash Working Capital

Cash Working Capital ("CWC") is the average amount of capital provided by investors, not including plant in service and other measurable rate base items, which represents the amount of cash needed between the time expenditures required for services and the time collections are received. (Thenmadathil Direct, p. 6, ln. 8-11.) OG&E utilized the lead-lag study approach to calculate cash working capital. Per that study, OG&E is requesting a decrease to test year CWC of $15,458,364. (Thenmadathil Direct, p. 6, ln.14-17.) After this adjustment, the ending balance of CWC results in a decrease to rate base of $20,797,067. (Thenmadathil, Direct, p. 6, ln. 19.) OG&E did not include depreciation, deferred tax expense, investment tax credits, or common equity return in the calculation of CWC.

PUD agreed with OG&E's methodology for calculating CWC, but made a slight adjustment based on their recommended final level of operating expenses as compared to the expense levels requested by the Company. This difference resulted in an additional decrease of $476,499 to OG&E's requested CWC adjustment. No other party opposed the Company's methodology for calculating CWC or the calculation itself.

The ALJ finds that the adjusted CWC is necessary and reasonable and that the Commission should adopt OG&E's CWC with PUD's adjustment thereby reducing rate base by $21,273,566 dollars.

b. Prepayments

OG&E proposes adjusting the year end prepayment balance to a 13 month average. (Thenmadathil Direct, p. 6, ln. 28-29.) No party opposes this adjustment, but PUD, AG and OIEC asked to increase the prepayment balance to reflect the end of the six-month post test year period, resulting in a prepayment balance of $3,880,336. (Hogan Responsive Testimony, p. 9, ln. 4-5.) OG&E agreed to that adjustment. (*See* Trial Exhibit No. 50.) The ALJ finds that the adjusted prepayment balance is necessary and reasonable and that the Commission should add to rate base $3,880,336 dollars for prepayments.

c. Materials and Supplies

In OG&E W/P B-3-8 pg. 13, OG&E proposes $77,250,587 for material and supplies based on a thirteen-month average, which OG&E contends represents an appropriate level of funding on an ongoing basis. PUD, AG and OIEC/OER propose an adjustment of $872,170 dollars, which OG&E accepted on Trial Exhibit No. 50. OG&E then made *a pro forma* deduction of $10,003,332 to remove certain third party transmission investments. The ALJ finds that the result of $65,883,504 dollars for materials and supplies is necessary and reasonable in cost and that the Commission should include that result in rate base.

d. Gas in Storage

OG&E proposes to decrease gas in storage inventory by $3,086,959. PUD Adjustment No. B-4 proposes to further decrease this expense in the amount of $857,885 to include the six-month post test year level. The ALJ recommends approval of that adjustment and finds that gas in storage should be reduced by $3,944,844. Gas in storage is now $9,690,675.

e. Fuel Inventories

OG&E proposes $72,490,664 for fuel inventories. PUD corrected that amount by $19,730,909 for a total of $92,164,573. OG&E used a thirteen-month, test year end average to arrive at $72,490,664. PUD recomputed the thirteen-month average to include known and measurable changes during the six-month post test year period to arrive at $92,164,573,[12] which the ALJ finds as necessary and reasonable and which the ALJ recommends that the Commission include in rate base.

f. Gain on Sale of Assets

During the test period, OG&E reaped $962,500 in gain on the sale and repurchase of a McClain facility turbine rotor in December, 2015 and $119,654 in gain on the June 30, 2015, sale of distribution facilities to the Choctaw Nation. (Tr. P.M. 5/10/2016, p. rdh-75-78.) Including those gains from these assets in rate base would reduce total Company rate base by $1,082,154. OG&E agreed to that total, but the AG came up with a different total, namely $1,262,322. (Farrar Responsive, p. 6-7.) The ALJ finds that OG&E's amount of $1,082,154 is the correct amount of total gain, that the Commission should adopt $1,082,154 for gain on the sale assets, and that the Commission should reduce rate base by that amount.

[12] Hogan, Resp. Test. Pg 8 ln 1-8.

g. Accumulated Deferred Income Tax

For Accumulated Deferred Income Tax ("ADIT") balances on December 31, 2015, OG&E proposes to reduce rate base by $1,481,089,618. (OG&E W/P B-3-14.) PUD contends that OG&E's estimated ADIT balance is reasonable, and PUD stated that no adjustment is necessary. (Thompson Responsive, p. 24, ln. 6-8.) After reviewing six-month post test year data, the AG and OIEC/OER recommend adjusting the actual ADIT balance as of December 31, 2015, to $1,480,273,771. (Garrett Responsive Exhibit MG 2.1.) OG&E concurs with that proposal. The ALJ recommends that the Commission reduce rate base by the amended ADIT balance of $1,480, 273,771.

h. Transmission Expenses Recovered from other LSEs

OG&E's W/P B-3-12 proposes adjustments for Transmission Investment, Accumulated Depreciation, Materials and Supplies, ADIT and other rate base items to reflect the removal of the portion of regionally allocated transmission projects assigned to other load serving entities ("LSEs") around the SPP, that should not be recovered from OG&E customers. (Thenmadathil Direct, p. 7, ln. 9-18.) No party opposes this adjustment. The cumulative net impact to rate base is a decrease of $655,558,467. The ALJ adopts OG&E's adjustments. The ALJ also adopts the updated 13-month average for associated Materials and Supplies of $76,378,417. (Hogan Responsive, p. 7, ln. 16.)

i. Customer Deposits

The test year balance for customer deposits was $75,933,115. (OG&E W/P B-6.) The AG, PUD, and OIEC/OER calculated an updated Customer Deposit balance at the end of the six-month post test year period. (Hogan Responsive, p. 10, ln. 7-12.) OG&E agrees to that adjustment, which increased customer deposits by $1,246,132. The ALJ finds that the Commission should adopt the adjustment to update the Customer Deposit balance resulting in an addition to rate base of $74,686,983 dollars.

j. Net Pension Benefit Asset

The Net Pension Benefit Asset ("net PBA") balance is the sum of the Prepaid Pension Obligation, other Accrued Benefit Obligations and associated ADIT. OG&E, OIEC/OER and the AG agreed that the test year net PBA balance should be reduced by $6,982,940 to reflect the six-month post test year period balance. (*See* Trial Exhibit No. 50.) This reduction results in a *pro forma* net PBA balance of $47,991,461. (Farrar Responsive, Exhibit ECF-1, p 9 of 18.) The

ALJ finds that the Commission should adopt that adjustment and accordingly add $47,991,461 to rate base.

k. Asset Retirement Obligations

OG&E's test year balance for its Asset Retirement Obligations was a decrease to rate base of $59,452,952. Both the AG and OIEC/OER updated this balance to the end of the six-month post test year period, which results in a total reduction to rate base of $63,292,180. (M. Garrett Responsive Testimony, Exhibit MG 2.1.) During the hearing on the merits, OG&E agreed to the adjustment for Asset Retirement Obligations. The ALJ adopts the adjusted balance for the test period and recommends that the Commission reduce rate base accordingly by $63,292,180.

l. Regulatory Assets and Liabilities

OG&E proposes an adjustment, which removes rider-related costs from the regulatory asset balance and updates regulatory liabilities to the six-month *pro forma* period. (Thenmadathil Direct, p. 8, ln. 7-8.) First, regulatory assets were decreased to remove the storm regulatory asset from rate base since this regulatory asset is recovered through a rider. This adjustment to regulatory assets results in a decrease of $16,956,230. (*Id* at, p. 8, ln. 9-10.) The ALJ adopts that adjustment.

Next, the pension regulatory liability at test year end was $23,187,190. The Company incurred additional pension settlement expenses through the *pro forma* period, primarily resulting from OG&E making lump sum payments to employees. As a consequence, the adjustment to regulatory liabilities results in an increase to rate base of $15,618,518. (Thenmadathil Direct, p. 8, ln. 20-25.)

The adjustment to decrease regulatory assets and decrease regulatory liabilities results in a decrease to the rate base of $1,337,712. (Thenmadathil Direct, p. 8, ln. 28-29.) No other party addressed these regulatory assets and liabilities. The ALJ finds that this adjustment to rate base is appropriate.

9. Proposed Rate Base

OG&E's application has a rate base of $4,152,329,406 dollars with a ROR of 8.088 percent showing a revenue deficiency of $92,494,692. The other parties calculated a rate base range from $4.185-4.209 billion dollars. After adjustments, OG&E agreed to a rate base of $4,200,544,953 showing a deficiency of $85,650,940.

G. Revenue and Expenses

1. Revenue

OG&E Schedule K-2.1 shows $1,150,374,539 for total revenue from Oklahoma retail jurisdiction. Of that amount, $1,133,073,736 came from *pro forma* revenues from electricity and $17,300,803 came from *pro forma* revenues from miscellaneous sources.

2. Customer Growth Adjustment

OG&E adjusted test year revenue, kWh, kW, and customer accounts for customers that left the system, are new to the system, migrated to another rate, or were re-billed. OG&E's initial application for rate relief reaches out two months into the six-month *pro forma* period, to August 2015, and performs these adjustments to usage levels based on actual end customer counts as of that time. (Cash Direct, p. 7, ln. 5-9.) These adjustments resulted in a revenue increase of $12,511,435 dollars and a net sales increase of 295,593,301 kWh sales to the Oklahoma jurisdiction. (Cash Direct, p. 6, ln. 15-16.) The AG and OIEC/OER recommended an additional increase of $5,375,062 dollars (M. Garrett Resp. Test., p. 21, l. 2) to revenue for customer growth and an additional 148,120,016 kWh to test year sales. This adjustment incorporates additional revenue as of the end of the six-month post test year period. During the evidentiary hearing, OG&E agreed with the AG and OIEC on their adjustment to customer growth. As a result, the ALJ finds that customer growth adjustment should be $17,886,497 dollars.

3. Weather Normalization Adjustment

OG&E used a 30-year weather normalization study, which resulted in a decrease to test year revenues of $6,366,505 and an increase to test year sales of 109,089,041 kWh. (Cash, Direct Testimony, p. 12, ln. 9-12.) No intervening party challenged OG&E's weather normalization methodology. The Commission should adopt OG&E's 30-year weather normalization adjustment.

4. Payroll

In calculating payroll expense, OG&E used the same methodology as applied in previous rate cases. This process included estimating the payroll expense and associated payroll taxes using June 2015 expenses updated for expected year-end head count and wage changes, including December 2015 pay raises. (Thenmadathil Direct, p. 11 and Rebuttal, p. 5.) OG&E's initial filing reflects an estimated December 31, 2015, payroll expense increase of $6,047,223 as

compared to test year end balances. After the books closed on the post test year period, OG&E provided updated information (Response to AG DR 2-11). The AG applied OG&E's payroll calculation method and annualized actual pay rates for actual employees as of December 31, 2015, to arrive at a recommendation for *pro forma* payroll expenses. This calculation decreased the payroll expense amount by $565,523 and resulted in a $5,481,700 increase to payroll expense and taxes when compared to test year-end balances. OG&E agreed to the AG's recommendation. (*See* Trial Exhibit No. 50.)

PUD based their recommendation on actual payroll expenses as experienced by OG&E in the twelve-month ending December 31, 2015. (Rush Responsive, p. 6.) The primary effect of this approach was to ignore the annual cost of the raises given to OG&E employees in December 2015. When combining PUD's recommendations for payroll expense and the resulting tax effect, PUD recommends a *pro forma* increase of $3,179,112 dollars from the level recorded by the Company at test year end. This amount is $2,302,588 less than the amount recommended by OG&E and the AG.

OIEC/OER disagreed with the OG&E, the AG and PUD positions. OIEC/OER proposes no increase in payroll expenses from those experienced by OG&E in the test year. (M. Garrett Responsive, p. 26.) This approach results in a payroll and payroll tax expense level which is $5,481,700 dollars less than the amount recommended by the AG and OG&E as well as $3,179,112 dollars less than the amount recommended by PUD.

The ALJ relied on historic data and best judgment to determine the fair cost to customers when new rates go into effect. The ALJ finds that a payroll expense adjustment based on the methodology of OG&E and the AG arrives at the employee cost, which most reasonably approximates the payroll expense, which should be recovered in prospective rates. The ALJ is persuaded that the three percent increase in costs, as reflected in raises given employees in December 2015, represents a known and measurable change from the level of test year expenses and should be included in rates.

5. Payroll Taxes

OG&E projects its payroll expenses to *pro forma* test year-end, with a corresponding adjustment to payroll taxes of $396,720 dollars. (OG&E Supplemental W/P H-2-23a.) The AG agreed with OG&E's payroll tax calculation method, but decreased the payroll taxes amount by $37,096 dollars to reflect updated payroll tax figures at the end of the *pro forma* test year period.

(Farrar Responsive, Exhibit ECF-1, p.13.) In Trial Exhibit No. 50, OG&E agreed to the AG's adjustment. The ALJ finds that the adjustment proposed by OG&E and the AG is based on the actual annual salary of OG&E employees as of December 31, 2015, should be approved.

6. TeamShare Expense

a. Short-Term Incentive Compensation

OG&E requests recovery for one-hundred percent of its short-term incentive compensation ("STI" or "TeamShare"), which varies from year-to- year. According to OG&E W/P H-2-24, the test year amount was $8,266,676, and the four-year average is $14,084,309. If you adjust to six-month post test year end, the four-year average is $15,427,914 company-wide and $14,209,108 for the Oklahoma jurisdiction. Unlike OG&E's long-term compensation ("LTI") and deferred compensation packages ("DCP"), when OG&E pays STI, OG&E pays STI to all its employees. (Ruden, Direct Testimony p. 4, ln4 to p. 5, ln 7.) STI is based on a "balanced scorecard" using operating performance measures and traditional performance measures. (Ruden, Direct Testimony, p. 4, ln 25 to p. 5, ln 7.) OG&E's standards are based on compensation surveys by independent third party consultants, although OG&E did not present at the evidentiary hearing any of the compensation surveys, and none of the consultants who authored those compensation surveys either testified or submitted a report. Nevertheless, OG&E witness Patricia Ruden testified that the compensation surveys showed what was necessary to attract and retain qualified employees. PUD agreed with the four-year average of TeamShare incentive payments, *i.e.*, $14,209,108. (Thompson Responsive, p. 27, ln. 7-10.) PUD also recommended including one-hundred percent of the OG&E's TeamShare costs, or $14,209,108. (Thompson Responsive, p. 27, ln. 7-10.) However, OIEC/OER and the AG recommended including only fifty percent of that expense. OIEC/OER's proposed adjustment results in $7,104,554 for the annual STI and added payroll tax of $498,740, for a total of $7,603,294.

The AG and OIEC/OER argue against full recovery for several reasons: OIEC/OER witness Mr. Mark Garrett presented a multi-state study on pages 28-39 of his Responsive Testimony. Mr. Garrett's study concluded that most utilities pay incentive compensation, but most public utility commissions allow recovery of little or no financial performance based compensation. The AG's witness Mr. Farrar presented a similar view. In essence, the AG and OIEC/OER contend that financial standards fail to identify any economic benefit to ratepayers beyond fifty percent.

Historically, the Commission has allowed recovery of either fifty percent of short-term incentive compensation or fifty percent of long-term incentive compensation, but not both. The rationale is that incentive pay generally encourages cost-savings, which benefits ratepayers and shareholders either equally or to an uncertain extent. As a result, past regimes of Commissioners were only willing to allow either fifty percent of STI or fifty percent of LTI, but not both.

The ALJ recommends PUD's approach, because in cost-of-service ratemaking, a public utility should be allowed to recover reasonable compensation for employees performing necessary functions for the provisioning of regulated services. The OG&E employees who are eligible for STI perform such functions. Until the Commission establishes a different scorecard for valuation, fair market value reflected by compensation surveys will have to suffice for the test of reasonableness of the expense. In that regard, OG&E presented evidence about its balanced scorecard approach, which is based on compensation surveys listed in Ms. Ruden's testimony. (Ruden, Direct Testimony p. 10.) Although, the ALJ did not see any of the surveys, OG&E's Opponents had the opportunity for discovery as well as the opportunity to present other witnesses and surveys. Thus, the ALJ recommends allowing recovery of STI to the extent STI is actually paid and up to one hundred percent of the maximum amount of $14, 209, 108 dollars.

b. Long-Term Incentive Compensation

OG&E proposes to include in rates $5,977,907 dollars for its long-term stock-based incentive plans given to corporate officers and executives. In support of the expense, OG&E witness Patricia Ruden testified that long-term incentive grants are intended to drive business decision-making that results in long-term Company performance and promote shareholder and customer value (Ruden Direct, p. 6, ln. 10-11). PUD recommended that OG&E only recover 25% of its long-term incentive compensation, which the ALJ calculates to be $1,494,476.75 dollars. (Thompson, Responsive Testimony, p. 27, ln. 19.) Basically, PUD used OG&E's LTI and DCP compensation metrics and re-graded the scores. OIEC/OER and the AG recommended excluding all long-term stock based incentive compensation for a reduction of $5,977,907. OIEC/OER and the AG once again argued that this compensation did not benefit ratepayers, and OIEC/OER added a new contention that this type of compensation encourages decision-making to improve the long-term value of OG&E stock, which consequently aligns corporate management with the shareholder interests. The ALJ submits that management and shareholders' interests typically align because of the nature of the agency relationship. The ALJ

also finds that PUD correctly assigned twenty-five percent to long-term compensation plans based on PUD's witness Mr. Thompson's expert opinion and that the allowed expense should therefore be $1,494,476 dollars.

7. Insurance Expense

OG&E compared test year insurance expense to the projected insurance expense for insurance policy period 2015/2016 using information provided by OG&E's insurance brokers. The difference between the test year and projected levels were recorded as a *pro forma* adjustment to increase expenses by $141,274. (Thenmadathil Direct, p. 10, ln. 13-16.) No party opposed this adjustment. The ALJ finds that OG&E's adjustment is a reasonable and appropriate adjustment.

8. Active Member Benefits

"Active member benefits" refer to medical, dental, life and long-term disability benefits for current employees. (Thenmadathil Direct at p. 10, ln. 6-10.) This adjustment compares actual test year levels with budgeted levels to arrive at a reasonable expense level going forward. OG&E recommends an increase of $212,825 for a total cost of $13,669,243 (MFR WP H-2-19). No party opposed this adjustment. The ALJ finds that this adjustment is reasonable and just.

9. Pension and Other Post Retirement Benefits

OG&E's adjustment H-2-18 establishes a level of pension and other post-retirement benefits expense based on an actuarial report provided by Fidelity. The level per the actuarial report was adjusted to only include amounts that would be classified as O&M expenses (operations and maintenance expenses). This adjustment decreases pension and retiree medical expense by $84,752 (Thenmadathil Direct, p. 9, ln. 25-31 through p. 10, ln. 1-3). The ALJ finds that adjustment to be necessary and reasonable.

10. Non-Qualified Pension Benefits

OG&E's adjustment H 2-18, included recovery of the costs for OG&E's Supplemental Executive Retirement Plan ("SERP"). PUD, the AG and OIEC/OER recommended a reduction of $1,860,147 to expenses to remove this non-qualified pension benefit. (Garrett Responsive, Exhibit MG 2.6.) Through Trial Exhibit No. 50, OG&E agreed to remove the SERP. The ALJ adopts the removal of the SERP and reduces expenses by $1,860,147.

11. Pension Regulatory Liability Adjustment

This adjustment consists of three separate components. First, *pro forma* pension regulatory liabilities recorded in the rate base were amortized over a two-year period. This amortization results in a credit to customers of $3,784,336. Second, the amortization for July 2014 related to the last rate case was removed. Removal of this amortization amount increases expenses by $929,506. Third, pension amortization related to the Arkansas jurisdiction was also removed, resulting in a decrease of $298,828. The total net *pro forma* adjustment is a credit to customers of $3,153,658. (Thenmadathil Direct, p. 14, ln. 3-9.) No party opposed this adjustment. The ALJ finds that the total net *pro forma* adjustment of $3,153,658 dollars is reasonable and just.

12. Ad Valorem Taxes

OG&E proposes to increase test year ad valorem tax expense by the average percentage increase experienced in the account over the past three-year period. The proposed increase is $4,166,889. OIEC/OER objected to the full amount, contending that the amount of the tax is negotiated with the Oklahoma Tax Commission ("OTC") every year and depends on the value of the assets and that the Commission should only allow OG&E to recover what OTC actually assesses. PUD proposes to reduce the ad valorem tax expense by $4,624,224 based on similar reasoning but with a different calculated tax liability. However, the ALJ finds that OG&E is entitled to recover ad valorem taxes paid. The ALJ also finds that the rates should be set based on the test period amount for ad valorem taxes and that any future deficiency between test year amount and what OTC assesses, should be preserved and allowed at the next rate hearing, which OG&E plans for 2017. Therefore, the ALJ recommends that the Commission reject the request for $4,166,889.

13. Wind Power Expense

This adjustment removes $886,310 of wind power education expense that was incurred during the test year. Of this total, $750,000 of wind power education costs was recovered through the Green Power Wind Rider ("GPWR"). The remaining balance of $136,310 included in the test year is not being requested for recovery. (Thenmadathil Direct, p. 17, ln. 28-31.) No party opposed this adjustment. The ALJ finds that this adjustment is reasonable and just.

14. Power Supply Utilities Expense

This adjustment is for an increase in the water cost associated with the operation of the Redbud Power Plant. Water costs for Redbud have been increasing due to increased utilization of the plant. OG&E proposes a *pro forma* adjustment of $196,404 to account for the increased water costs expected to occur by the end of the *pro forma* period. (Thenmadathil Direct, p. 18, ln. 3-6.) No party opposed this adjustment. The ALJ finds that this adjustment is reasonable and just.

15. Underground Vault Expense

OG&E proposes to include incremental labor and other costs related to the inspection and maintenance of new protection equipment installed in underground vaults and manholes. (Thenmadathil Direct, p. 18, ln. 17-25.) This adjustment increases operating expenses by $455,873 to pay for inspection and maintenance for new network protectors. No party opposed this expense. Therefore, the ALJ recommends that the Commission approve this expense.

16. Vegetation Management

OG&E is requesting an approximately thirty million dollar total Company vegetation management expense. That amount includes $23.4 million in distribution cycle work, $2.1 million dollars in distribution non-cycle work, $360,000 in distribution non-cycle work, and $4.5 million dollars in transmission work. (Cassada, Direct Testimony p. 15, ln. 25-28.) The thirty million dollar total represents an increase of $13,211,025 dollars to the vegetation management expense. Of that increase, $11,518,525 dollars is attributable to an eleven percent increase in new distribution assets, and $1,692,500 is attributable to growth in transmission. (Rowlett, Direct Testimony p.11 ln. 23-26.) That is an eighty-one percent increase for distribution assets and a sixty percent increase for transmission. The test year levels were $14,272,378 for distribution and $2,842,153 for transmission. (OIEC/OER M. Garrett, Responsive Testimony. p 55.)

The total vegetation request from OG&E is $13.2 million over test year amounts for distribution and transmission. (Tr. A.M. 5/6/2016, p. rdh-76, ln. 2-8.) This is only a $5.5 million dollar increase from the average five-year spend for distribution and transmission vegetation management. (Rowlett Direct, p. 12, ln. 2-3.) In addition, OG&E is proposing a vegetation management tracker which will account for OG&E's spending variances above or below the level recovered in base rates between rate cases. (Rowlett Direct, p. 12 ln. 3-6.)

OG&E uses only independent contractors for vegetation management, and during four of the last five years, OG&E has not met the four-year-trim cycle required by Commission rule OAC §165:35-25-15. OG&E previously requested and obtained from the Commission a System Hardening Rider as a means for a one-time catch-up, so OG&E could meet a four-year trim cycle in future years. The System Hardening Rider has now expired, and OG&E now requests approval of additional funds from ratepayers to catch-up and maintain the trimming required for its system.

The AG, OIEC and PUD oppose increased funding levels for vegetation management, and they object to setting up OG&E's proposed tracker. The AG presented the only engineer Mr. Mara who contends that OG&E had an overly expensive approach to vegetation management. (Mara, Responsive Testimony on p 23.) The following summarizes Mr. Mara's position: OG&E should adhere to the Commission mandated four-trimming cycle; OG&E should maintain the two-tier trimming system to reduce the need to increase OG&E's trimming budget; the Commission should require a quarterly report from OG&E on the status of OG&E's vegetation management plan; the budget for distribution cycle trimming should be reduced by $4,354,171; the budget for the non-cycle distribution trimming should be reduced by $657,027; and the proposed vegetation management tracker is unnecessary if OG&E meets the foregoing requirements.

OIEC/OER's opposing position appears in witness M. Garrett's testimony seen on pp 55-58 of his Responsive Testimony on Revenue Requirement Issues. OIEC/OER Witness M. Garrett contends that OG&E is behind on tree trimming, because OG&E failed to meet its duty to maintain its distribution system, and as revenues from the System Hardening Rider declined, OG&E failed to keep pace with its trimming obligations. He contends that the cost to catch-up should be paid by earnings per share. He also contends that OG&E failed to show that it needs more than the five-year average of $21.5 million dollars for distribution and the test year amount for transmission. Figure 2 is a chart prepared by OG&E witness Mr. Cassada, showing five year funding under the System Hardening Rider.

Figure 2

Chart 6

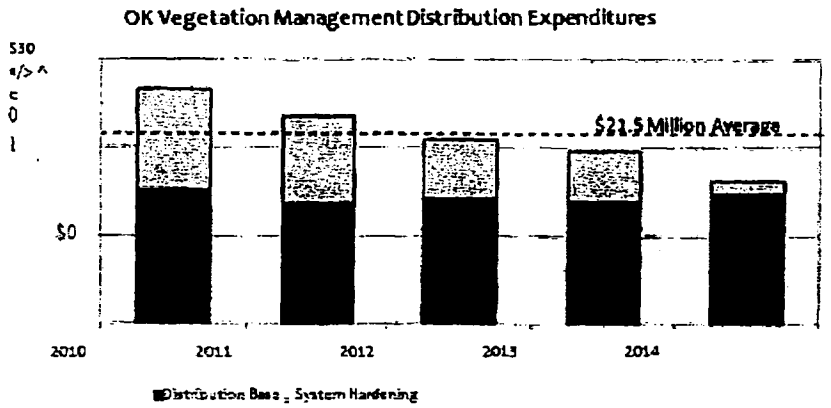


Figure 2 shows that OG&E has not needed more than the five-year average of $21.5 million during four out of five of the last five years.

PUD's witness Mr. Thompson agreed with OIEC/OER about the five-year average and also noted that the proposed increase for transmission should be denied, because the $1.69 million dollar herbicide treatment that will occur beyond the test-year and six months.

The ALJ recommends $21.5 million dollars for distribution and $2,842,153 for transmission based on the five-year average expense. The ALJ also recommends postponing $1.69 million dollars for the transmission line herbicide. The ALJ finds that the herbicide expense follows industry custom and practice, and that the cost is reasonable and necessary but the expenditures will occur outside the test period for this ratemaking. The ALJ would ordinarily recommend that the Commission pay the herbicide expense now to avoid another rate case, but OG&E has already announced that it will file another rate case in 2017. Therefore, it is unnecessary to pay the herbicide bill at this time. The ALJ further opposes OG&E's proposal for a vegetation management tracker. OG&E would like for the Commission to believe that OG&E may need to increase vegetation management expenditures between ratemakings. However, the ALJ finds that levels for distribution and transmission are adequate, and so a tracker is unnecessary.

17. Reallocation of Corporate Costs

OG&E's Application includes a *pro forma* adjustment increasing O&M expense by $6,057,685 to reflect an increase in OG&E's share of the cost for certain administrative services

provided by the Holding Company. The adjustment resulted from a change in the services allocated to Enable Midstream Partners LLC ("Enable") during the test period. (Thenmadathil Direct, p. 11; Updated Response to OIEC D.R. 2-16.) During the full evidentiary hearing, OG&E reduced the requested amount to $3,938,926. The reduced amount allegedly reflects actual costs allocated to Enable at the end of the six-month post test year period. (Tr. 5/9/2016 a.m. at p. 13-14.)

The AG recommended denial of the corporate allocation adjustment as last amended, because the costs are unnecessary to serve retail customers (Wielgus Responsive Testimony, p. 15). OIEC/OER also opposed the amended corporate allocation adjustment, because the cost-sharing agreement between OG&E and Enable ended in January 2016, which is outside the *pro-forma* test year. (M. Garrett Responsive, p. 59). OIEC/OER also cautioned that a "windfall" for OG&E could occur if the Holding Company is able to further reduce or eliminate the costs at issue. (*Id.* at 60.) PUD recommended no adjustment to the expense level requested by the Company.

In response to opponents' concerns, OG&E witness Scott Forbes filed rebuttal testimony on April 11, 2016. In that testimony, Mr. Forbes testified that, since 1986, OG&E has been sharing the costs of administrative services such as auditing, accounting, finance, treasury, human resources, risk, information technology and supply chain service with its affiliate, Enogex (Forbes Rebuttal, p. 3 and 6), and that a change to the sharing of those costs began in May 2013 with the formation of Enable Midstream Partners that resulted from the combining of Enogex and CenterPoint Energy's mid-stream business. (*Id.* at p. 3-4.) He further testified that upon the formation of Enable, the Holding Company entered into a three-year service agreement to continue providing to Enable the administrative services previously provided to Enogex. (*Id.* at p. 4.) Regarding contentions that the service contract with Enable extended beyond the *pro-forma* test year, Mr. Forbes stated that all the cost increases were caused by services cancelled by Enable no later than the of the end of December 2015 and that the effect of those cancellations were immediate. (Forbes Rebuttal, at p. 5; Tr. P.M. 5/10/2016, p. 70; 92.) In response to claims that the services at issue are unnecessary to the provision of service to OG&E's customers, Mr. Forbes stated those services are "integral" to the operations of a company such as OG&E and that it is common for utility holding companies to provide those services so as to "reduce the cost of having redundant administrative costs when a company has multiple subsidiaries." (Forbes

Rebuttal, p. 6.) Further, Mr. Forbes disagreed with the contention that OG&E could reap a "windfall" if administrative services were reduced or eliminated, stating: "The remainder of the allocations primarily deals with fixed information technology and related infrastructure costs, which can't be eliminated, as OG&E relies on that technology and infrastructure." (*Id.*)

The ALJ agrees with OG&E's contention that the services previously paid for in part by Enable and now reallocated to OG&E constitute core administrative functions are required by OG&E. The ALJ also finds that OG&E customers have benefited from a sharing of administrative costs since 1986 (Forbes Rebuttal, p. 3), and that while some parties speculate that the increased costs to the utility caused by the withdrawal of Enable could be excessive, they presented no credible evidence showing either that OG&E's request is unreasonable or that OG&E could receive a windfall.

The ALJ finds that the Company's estimated share of the cost-of-services no longer reimbursed by Enable is $6,057,685, and that by the end of December 2015, Enable only terminated some of those services resulting in a utility allocation of only $3,938,926. When Enable subsequently terminates all the services, the share of costs embedded in the rates paid by OG&E's customers will continue at the lower amount even after Enable no longer contributes to the payment of those costs. That is, customers will continue to benefit from the offsetting Enable contribution even after Enable terminates those services. As a result, the ALJ finds that a *pro forma* adjustment in operating expenses to reflect an increase in corporate allocations in the amount of $3,938,926 is appropriate.

18. Bad Debt Expense

The bad debt *pro forma* adjustment includes cost for uncollectible revenues OG&E will experience, net of the fuel component of the customer's bill. This adjustment is made to reflect the expected increase in bad debt not associated with fuel, since the fuel component of bad debt flows through the FAC. OG&E used a four-year average uncollectible rate and multiplied it by the *pro forma* revenues net of fuel to arrive at a new bad debt expense level. This adjustment increases operating expense by $72,914 (Thenmadathil Direct, p. 13, ln. 7-13). No party opposed this adjustment, but PUD updated this adjustment to the six-month post test year period and decreased the total adjustment by $27,418. (Patel, Responsive, p. 18, ln. 1-2.) The ALJ finds that the method utilized by OG&E is fair and reasonable and accepts OG&E's adjustment

(as updated by PUD). Therefore, the ALJ finds that expense should be increased by $45,496 for bad debt expense.

19. Customer Service Expense

OG&E proposes a customer service expense for an outside services contract for a call center. (Thenmadathil Direct, p. 14, ln. 22-27.) This new staffing approach will allow OG&E to achieve an increase in its ability to respond to customer calls in thirty seconds or less. The new contract was signed in September 2015 and the contract took effect in December 2015. Reductions in OG&E staffing occurred through attrition by December 31, 2015, and so the cost for a call center contract should be reflected in base rates in order to match the savings associated with reduced staffing levels that occurred during the *pro forma* period. The *pro forma* adjustment is an increase to expenses of $678,600. No party opposed this adjustment. The ALJ approves this new staffing approach and adopts the adjustment in the amount of $678,600.

20. Interest on Customer Deposits

OG&E makes an adjustment to include interest on Customer Deposits in its expenses. The amount of OG&E's interest expenses on these customer deposits is $1,218,873. (Thenmadathil Direct, p. 17, ln. 1-3.) PUD updated the Company's Customer Deposits balance through December 31, 2015, increasing the level of customer deposits. (Hogan Responsive, p. 12, ln. 16-19.) This results in a corresponding increase to interest expense of $18,205. No other party addressed this adjustment. The ALJ finds that OG&E's proposed amount as updated by PUD should be adopted, and that the interest on customer deposits should be $1,237,078 dollars.

21. Dues and Donations

PUD recommends an OG&E's operating expense of $115,673 to reflect a 50/50 sharing of the dues and memberships for chambers of commerce, other miscellaneous memberships and economic development initiatives for the utility. (Dodoo Responsive, p. 5, ln. 13-19.) The ALJ finds that some of the costs related to civic dues and memberships are beneficial to customers as well as the shareholders, and should thus be shared as proposed by Staff. Therefore, the ALJ adopts $115,673 for dues and donations.

22. Advertising

OG&E asks for $750,785 dollars in advertising expenses. PUD objects to $537,115 for customer education on energy efficiency, VPP and DSM, because Order No. 605737 addressed that funding. The ALJ agrees with PUD and limits the advertising expense to $213,670 dollars.

23. Amortization of Gain on Sale of McClain Plant Rotor

OG&E has a gain on the sale of assets, namely $962,500 dollars for the sale of a rotor for the McClain Plant and $119,654 dollars from the sale of distribution facilities to the Choctaw Nation. The dispute concerns the amortization of the rotor. OG&E wants thirty years, while OIEC/OER and the AG want two years. The ALJ notes that the gain here is unusual in origin. OG&E ordered a new rotor from its manufacturer. Another utility had rotor failure and badly needed OG&E's new rotor. OG&E accommodated the other utility by switching places in the manufacturer's delivery queue. The result was that OG&E paid a reduced price for a rotor when it was delivered. The resulting savings are what the other parties are calling gain. The ALJ finds that the Commission should adopt OG&E's proposal to amortize the gain over the remaining life of the plant resulting in an annual credit to ratepayers $32,083 dollars.

24. Amortization of Smart Meter Stranded Assets and Web Portal Costs

OG&E is requesting that Smart Grid stranded assets and the Smart Grid Web Portal costs be amortized over a six-year period. (Thenmadathil Direct, p. 17, ln. 12-20.) These costs involve the stranded assets associated with analog meters that were replaced by smart meters in 2010, 2011 and 2012, as well as the costs for implementing the Smart Grid informational portal in 2010.

OIEC/OER proposed an amortization period of fifteen years as opposed to OG&E's request for a six-year amortization period. (M. Garrett Responsive, p. 62, ln. 16-18.) OIEC/OER argued that OG&E should be penalized for failing to file a 2013 rate case (*Id.* at p. 62, ln. 9-12), and that a 15-year amortization period is the same amortization period ordered by the Commission for PSO's stranded assets resulting from PSO's smart meter deployment. (*Id.* p. 62, ln 18-19.) However, OIEC/OER witness M. Garrett admitted during cross examination that the amortization period ordered by the Commission in the PSO cause was approximately 10 years. (Tr. P.M. 5/18/2016, p. 18-19.) No other party challenged the Company's request.

The ALJ finds that OIEC/OER provided no valid rationale to support their fifteen-year amortization period. According to OG&E Witness Rowlett, in Cause No. PUD 201000029, OG&E originally proposed to amortize the cost over 10 years, but, as part of a comprehensive settlement, it was determined that the stranded meter and web portal costs were to be amortized over six years. (Rowlett Rebuttal, p. 20, ln. 23-26.)

The ALJ notes that OG&E has earned no return on either of the stranded assets or the web portal costs in the intervening years and finds that the six-year amortization period is consistent with previous Commission orders. No persuasive evidence has been provided to justify a longer amortization period. Further, the ALJ does not believe the Commission should adjust amortization periods in order to penalize the Company for some parties' belief that OG&E should have filed a 2013 rate case. Therefore, the ALJ adopts OG&E's amortization of $6,742,797 included in adjustment W/P H-2-41.

25. Regulatory Asset Amortization

OG&E proposes two adjustments that amortize regulatory assets. W/P H-2-35 amortizes regulatory assets associated with the cost of consulting fees for intervening parties in certain Commission cases. (Thenmadathil, Direct Testimony, p. 15, ln. 23-25.) The costs are for the OSU Wind Project independent evaluator, the 2012 IRP independent evaluator, and the fees of AG and PUD consultants for Cause No. PUD 201400229. The total costs are $831,865 dollars. OG&E proposes a two-year amortization resulting in annual expense of $415,932 dollars. PUD objected to paying consultant fees in Cause No. PUD 201400229, because the projects were not complete. The ALJ finds that the Commission denied all relief in that cause. The ALJ recommends that the Commission adopt OG&E proposed amortization for W/P H-2-35.

OG&E's second adjustment appears in W/P H-2-49, which incorporates the Commission approved Red Rock Regulatory Asset amortization into the revenue requirement, while removing miscellaneous amortizations from the Arkansas jurisdiction. The net impact of this second adjustment is a decrease of $7,173 dollars. No party opposes this adjustment. The ALJ recommends that the Commission adopt the second adjustment.

26. Interest Synchronization

PUD proposes Adjustment No. 1 in Section J, Schedule 3 of PUD's Accounting Exhibit in the amount of $1,733,764. The Commission finds that this adjustment is necessary to modify the interest components of OG&E's income tax calculation to capture the impacts of PUD's proposed adjustments to rate base, ROR and the operating income statement. The ALJ finds that this adjustment is necessary to reflect the appropriate level of interest to be included within rates on a prospective basis and that PUD's interest synchronization adjustment should be approved.

H. Depreciation

OG&E initially proposes a depreciation expense of $294,831,130 dollars based on John J. Spanos' depreciation study of OG&E assets as of December 31, 2014. Obviously, Mr. Spanos' study ended in the middle of the test period for this ratemaking. However, OG&E's Supplemental Package updated OG&E's depreciation expense to six months post test year, resulting in $314,602,372 dollars for OG&E's test period amount. (OG&E W/P H-2-21.) In opposition, certain interveners contend that the test period amount should be around $270 million dollars based on their depreciation studies.[13] In that regard, all of the depreciation witnesses started out with the same amounts as Mr. Spanos for remaining original cost of depreciable assets. The differences in end results center around what should be added or subtracted from those same 2014 base amounts.

OG&E included $60.2 million dollars for all depreciation unrecovered since the 2012 rate order. However, Mr. Spanos' 2014 depreciation study only covers depreciation of utility assets even though OG&E also seeks recovery of the Holding Company depreciation. Nevertheless, Mr. Spanos' opponents each calculated a total depreciation expense and subtracted that depreciation expense from OG&E's $314.6 million dollars to arrive at a reduced depreciation expense. AG witness Mr. Cook recommended a reduction of twenty-four million dollars. PUD witness D. Garrett proposes a reduction of $36 million dollars (D. Garrett Responsive, p. 9, Figure 2.) FEA's witness Mr. Andrews proposed reductions of $37.2 million dollars (Andrews Responsive p. 22, ln. 4-8). And, OIEC/OER's witness Mr. Pous recommended $45.1 million dollars in reductions. (Pous Responsive p. 8, ln. 17-22.)

In any event, the term "depreciation" refers to an accounting method for distributing fixed costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of the depreciation expense is part of that year's total cost of providing electricity. Normally, the period of time over which the fixed capital cost is allocated to the cost-of-service is equal to the period of time over which an item renders service, that is, the item's service life. As used in this report, the term "average service life" ("ASL") refers to the average expected life of all units within a particular group, and it is the arithmetic average of the lives of those units.

[13] Note, PUD proposed a depreciation expense of $260.89 million dollars for the test period.

Mr. Spanos calculated annual depreciation by the straight-line method using the average service life procedure and the remaining life basis. Mr. Spanos' calculated remaining lives and resulting annual depreciation accrual rates were based on his opinion about attained ages of plant in service and the estimated ASL and salvage characteristics of each depreciable group. Mr. Spanos proposes amortization accounting or vintage pooling for most general plant accounts.

OG&E's accounting policy has not changed since the 2009 depreciation study used in the 2012 rate case. However, there have been significant changes in past and future retirement plans for assets, particularly at steam facilities. These changes have caused Mr. Spanos' proposed remaining lives for many accounts to fluctuate from those proposed in his 2009 depreciation study.

The dispute here involves differences of expert opinion about ASLs of assets and salvage estimates. Mr. Spanos' testimony increases the revenue requirement by adding new depreciable assets and increasing depreciation for existing assets. With respect to existing assets, Mr. Spanos shrank some ASLs, which raised accrual rates on remaining original costs for those assets. The Interveners disagreed with a number of changes to service life and accrual rates. The major issues were ASLs for major assets, corresponding accrual rates, production net salvage, wind farm life span, Holding Company depreciation, utility electric company amortization of software, mass property life analysis and mass property net salvage.

The service life issue pertains to several accounts, covering the following depreciable groups: steam production, other production, transmission and distribution. The ALJ will start with major assets other than wind power and mass property accounts, which are discussed in separate sections below. Interveners, in particular FEA, object to OG&E's decision to shorten certain ASLs for major assets. FEA's witness Mr. Andrews contended that he got a better fit on the Iowa Curves with curves that extended ASLs several years thereby reducing the annual depreciation expense.

Both sides of the dispute used asset survivor curves to forecast remaining useful life of major assets. In this method, either actual asset retirement dates or plant balances are used to develop an observed survivor curve, which can be fitted to an Iowa Curve to forecast the service life for a type of asset. An observed survivor curve represents the portion of original plant remaining in service each year. It is obtained from a frequency curve by cumulatively subtracting the portion of plant retired year from one-hundred percent at placement in service to

zero percent at retirement of all units. When dealing with groups of property, all units seldom retire at the same time. Some units retire at an early age; many retire at a generally accepted average age; and a few units retire at a late age. The problem here is twofold: OG&E has retired a limited number of major facilities over its history, and the Commission has extended service life of major facilities based on replacement of parts that were capitalized for ratemaking purposes. Because of incomplete data sets, the parties resorted to the Iowa Curves to statistically forecast ASLs for such assets. Along that line, Mr. Spanos' opponents contend that their Iowa Curves fit better and should be adopted. However, the ALJ submits that such a fact by itself is not dispositive. The ALJ finds that a survivor curve should not be taken at face value without considering what is happening in the account. An observed survivor curve shows when assets are pulled from the market, but the curve itself does not show any cause of retirement at any point. A depreciation must provide a reason for retirements to forecast an ASL, even if the Commission does not require a detailed retirement study as recommended by OIEC/OER witness Mr. Pous. An item may be pulled for reasons other than wear, *e.g.*, manufacturing defect, destruction, theft, obsolescence and change in system design. The issue is, therefore, how to view Mr. Spanos conclusions. For the ALJ, the Interveners had reasonable access during the discovery to all necessary records for these categories of depreciable assets, and Mr. Spanos exercised informed judgment based on his four depreciation studies over a fifteen-year period as well as his study of retirement data from other utilities that had similar equipment to that of OG&E. Opponents failed to persuade the ALJ that Mr. Spanos' opinion was untrue, unreasonable or excessive. As a result, the ALJ adopts Mr. Spanos' opinion about ASLs for major assets and resulting accrual rates.

1. Production Plant Net Salvage

OG&E proposes terminal and interim negative net salvage values exceeding $317 million dollars for its steam and other production generating facilities. That amount is based extensively on Mr. Spanos' "informed judgment," but he provided little of value to support his $225 million dollar estimate for net terminal salvage to pay for future dismantling and decommissioning of production generating units still in service.[14] The ALJ notes that the OG&E application represents the first time that OG&E has asked for net terminal salvage as a separate item in depreciation. In regard to net terminal salvage, Mr. Spanos advised that OG&E needed to

[14] The $225 million comes from DR AG-5.

perform a dismantling and decommission study on each generating facility, but OG&E chose not to do so for alleged time constraints in the ratemaking process and directed Mr. Spanos to find another way to calculate net terminal salvage. During the evidentiary hearing, Mr. Spanos admitted that he had never decommissioned a plant and never performed a dismantling and decommissioning study. Nevertheless, he estimated net terminal salvage for a steam plant at $40/ kW based on a published study from 1996, where Mr. Spanos assumes that dismantling and decommissioning costs for a steam plant have not changed significantly in twenty years. He also estimates $10/kW for other production plants, excluding wind, and $5/kW for wind, all based on a confidential study, which Mr. Spanos refused to produce, because he did not have access to the underlying data. Consequently, there is no way to evaluate or substantiate the confidential study, which the ALJ must assume covers restoring a site to bare ground. However, we know very little about OG&E s future plans for its generating sites, because OG&E decided not to do a dismantling and decommissioning study on any generating facility, even though OG&E realized that it wanted terminal salvage back in 2008 and did not apply for it during the 2012 rate case. From the last IRP, we have tentative closure dates, but we do not know what OG&E can resell or reuse at any site, which puts in question Mr. Spanos' opinion about net salvage.

Nevertheless, PUD contends that even though OG&E lacks a dismantling and decommissioning study, the Commission should allow OG&E to recover one-half of the proposed annual net terminal salvage, *i.e.*, around nine million dollars by PUD's estimate. In that respect, there is a difference of opinion about the amount OG&E requested for net terminal salvage. OIEC/OER used $19.9 million dollars. PUD used $18.3 million dollars. And the ALJ uses $15.6 million acknowledging that an additional 2.7 million dollars is already in the net salvage expense for the test period.

Nevertheless, before the Commission allows any additional recovery for net terminal salvage, the Commission must make some major policy decisions. First, the Commission is only required to allow recovery for lawful obligations of the utility attributable to the provisioning of regulated service. Here, there is no federal or state requirement to cleanup any generating site. OG&E has only expressed a desire to close facilities at future dates. Therefore, there can be no right to recover above net salvage until OG&E explains when and how it will close either a unit or an entire facility. Next, traditional regulatory thinking is that it is desirable to have a depreciation system for ratemaking that has users pay for services when they receive them, and

does not allow the utility to recover an expense before the expenditure is made. Following the traditional approach means that there should be no interim recovery for terminal salvage. Be that as it may, the third hurdle is that OG&E has not allocated any net terminal salvage to its wholesale operations. In this ratemaking, OG&E is phasing out its wholesale operations by moving the generation to the retail side. An unanswered question is whether AVEC, OG&E's last wholesale customer, is going to pay any part of net terminal salvage. In any event, if you get past the first three hurdles, there are five accounting options to consider.

The first option requires an adjustment to the depreciation rate using the relationship 1-S, where S is the forecasted salvage. Positive salvage reduces the annual accrual, and negative salvage increases the accrual. This approach is most commonly used in group accounts. This accounting treatment is recognized in a generally accepted accounting principle in Statement of Accounting Standards No. 19 (FASB 1977), which applies to oil and gas operations.

A second option involves ignoring salvage in the depreciation calculation, and then recognizing positive salvage as income and negative salvage as an expense at the time the asset is retired. However, this current period approach fails to match expense with revenue over the useful life of the asset.

A third option would be to establish a separate estimated allowance (reserve) for net terminal salvage for each account that is experiencing negative net salvage. The amount of the annual accrual would need to be based on consideration of past experience, forecasted needs and short-term cash needs for the cost of removal.

A fourth option would be to establish a deferred charge to amortize over the future negative net salvage incurred in any given year. However, this method fails to match revenue and expense during the productive life of the asset and does not produce full cost-of-service figures.

A fifth option is to establish a funded reserve for estimated future negative net salvage, where funds are collected for this reserve using a straight-line or sinking fund accrual. The ALJ suggested this method in his report in Cause No. PUD 201400229, but the final order in that cause did not address that proposal, because the final order in that cause denied all relief requested by OG&E.

At this point, the ALJ makes the following findings: An abandoned facility can become a public nuisance, but most power plant sites will remain power plant sites indefinitely because of

the supporting infrastructure and the difficulty in siting new plants elsewhere. Nevertheless, the Commission needs to consider how to fund closure when a facility becomes uneconomic. The problem here is that OG&E's closure plans are highly vague, but the ALJ agrees with PUD that we need to start somewhere. Therefore, the ALJ recommends that the Commission allow recovery of $7.8 million dollars, which represents one-half of the requested terminal salvage ($15.6 million dollars) based on the ALJ's estimate of net terminal salvage.

2. Wind Farm Life Span

OG&E proposes to keep the life span of wind units at twenty-five years, while the AG, PUD and OIEC want to reduce the annual depreciation expense by $6.5 million dollars through extending unit life to thirty years. The central issue consists of what should be the ASLs for different makes and model wind turbines used at the three OG&E owned and operated wind farms.

To begin, the ALJ notes that nobody offered testimony about the make, model, productive capacity or economics of any of OG&E's turbines at any point in time. Next, the proponents of an extended ASL contend that OG&E failed to prove that the ASLs should be twenty-five years. However, the ALJ understands that Mr. Spanos was using the existing ASL set by Commission orders, when the Commission added these wind assets to rate base. Therefore, the proponents of a thirty-year ASL bear the burden of persuasion on service life. Along that line, they presented evidence in the form of references to orders from other state utility commissions, published studies on wind turbines at certain sites and a brochure from Gamesa, a company that refurbishes wind turbines (Trial Exhibit No. 66). That evidence purportedly shows that some wind turbines have ASLs of thirty or more years. However, none of that evidence shows that the units in the proponents' materials are the same or similar to those used at any OG&E wind farm or that any of the study sites have similar wind conditions to those of OG&E wind farms.

The ALJ further finds that determining a useful life for a wind turbine requires an engineering analysis to predict how long a particular unit will remain economic. For a wind farm, the items in rate base consist of the turbines (ex-works), foundations, electric installation, grid connection, control systems, consultancy, land, financial costs and the road. The ALJ finds that the main parameters governing wind power economics include investment costs, such as auxiliary costs for foundations and grid connection, operation and maintenance costs, electricity

production, average wind speed, turbine lifetime and discount rate. To the ALJ, the most important parameters are turbine electricity production and investment costs and that as electricity production depends to a large extent on wind conditions, the model of turbine, and the economics of wind power are site specific.

The ALJ observes that in recent years, four major trends have dominated the development of grid-connected wind turbines: Turbines have become larger and taller; the efficiency of turbine production has increased steadily; the investment costs per kW have decreased; and operations and maintenances costs, which include insurance, regular maintenance, repair, spare parts and administration, have also dropped due to new turbine designs that require fewer service visits and less turbine downtime. For the ALJ, an unanswered question in this docket is whether new, more efficient turbines will replace OG&E's turbines within the proposed extended lifespan for the existing OG&E turbines. The ALJ was a Commission attorney when the Commission approved the OG&E wind farms. Based on that experience, the ALJ recalls that OG&E has three, three megawatt turbines and the rest are smaller units, presumably gearbox units. Presently, big units by Siemens, Enercon and Vesta have nameplate capacities around 7.6 megawatts. Obviously, the levelized cost of electricity generated by the OG&E turbines is up against levelized costs for electricity from newer, more efficient turbines.

When the Commission approved the OG&E units, the Commission based useful life on the manufacturer's suggested useful life, which was then twenty-five years. When a wind turbine reaches the end of the manufacturer's suggested useful life, the issue is whether to either overhaul or upgrade components of the ex-works or to install a new turbine possibly requiring a new tower and foundation. The operator's choice depends on the aforementioned, site specific parameters as well as other factors impinging on wind farm economics, such as, USFW "kill permits" limiting production, congestion on transmission lines, take or pay contracts, the cost per kW/acre compared with other alternative energy sources and the cost per kW/mile above the SPP postage stamp rate for transporting electricity from the wind farm to the load center. The kW/mile cost includes cost of transmission equipment, line loss, the cost to periodically ramp up current and the cost to step down at the load center. Here, the problem for proponents of a thirty-year life span is that they lacked an engineering study showing that at each OG&E owned wind farm, the model or models of wind turbines used at that wind farm would be economic to operate

for thirty years. As a result, the ALJ recommends keeping the ASL at twenty-five years and not reducing the depreciation expense by $6.5 million dollars based wind turbine lifespan.

3. Holding Company Depreciation

OG&E asks for $10,409,178 dollars for annual depreciation associated with the Holding Company investment. The largest component of the investment in the Holding Company consists of various software systems. The useful life of these software systems as seen in the 2009 Holding Company Depreciation Study is only half as long as Mr. Spanos is now assigning to those software systems at OG&E. Restoring the useful life for the software reduces depreciation by $4.3 million dollars based on plant as of December 2014 and $5.2 million dollars as of December 2015. The ALJ recommends restoring service life to the 2009 Holding Company study level and reducing the depreciation expense by $5.2 million dollars for Holding Company depreciation.

4. Utility Electric Company Amortization of Software

Mr. Spanos recommends extending the three-year amortization of investment in software to ten years, but he fails to properly capture the ongoing impact of the exiting three-year amortization. OG&E's $29 million dollar investment in software will be fully accrued before the Commission sets new rates in this cause. Mr. Spanos' theoretical calculation incorrectly assumes that the proposed ten-year amortization is applicable as of the end of 2014. If adopted, that assumption would result in double recovery of the majority of the investment reflected in his amortization calculation. Proper recognition that the three-year amortization will remain in place at least through the middle of 2016, reduces the revenue requirement by $3.1 million dollars. As a result, the ALJ recommends reducing the depreciation expense by $3.1 million dollars for utility electric company amortization of software.

5. Mass Property Service Life Spans

For FERC mass property accounts, OIEC/OER's witness Mr. Pous, PUD's witness Mr. Garrett, and FEA's witness Mr. Andrews each recommended using asset survivor curves that differ from those used by Mr. Spanos. Because each expert used the same statistical analyses, the differences between witness estimates results from the application of informed judgment. (Spanos Rebuttal Testimony, p.27, ln 10-12.) The central issue is, therefore, whether Mr. Spanos could substitute his informed judgment in place of better curve fitting.

The witnesses opposing Mr. Spanos want to reduce the depreciation expense by $6.7 million dollars by extending ASLs in several mass property accounts. Mr. Spanos generated shorter ASLs in those accounts by visually fitting curves to correspond with his opinion about ASLs derived based on a long career in depreciation and from fifteen years of familiarity with OG&E equipment while performing four depreciation studies for OG&E. Mr. Spanos' opponents contend that their Iowa Curves fit better and result in longer ASLs.

In response, the ALJ finds that a survivor curve should not be taken at face value without considering what is happening in the account. An observed survivor curve shows when assets are pulled from the market, but the curve itself does not show cause of retirement at any point. Consequently, a depreciation witness has to have evidence to corroborate a service life derived from his actuarial analysis. For mass property, Mr. Spanos graphed survivor curves for accounts of indefinite duration, typically containing products with different makes, models and manufacturers suggested useful lives. While, Mr. Spanos had access to the OG&E engineers and asset life records, Mr. Spanos did not provide any way to evaluate his average service life analysis.

OG&E relies on Mr. Spanos' informed judgment to support his conclusions. The concept of informed judgment is explained in Trial Exhibit No. 57, an excerpt from NARUC's *Public Utility Depreciation Practices* August 1996. At page 128 of Trial Exhibit No. 57, the NARUC Finance and Technology Committee discusses the concept of "informed judgment," which is the subjective part of a depreciation study. According to that NARUC Committee, informed judgment is based on a combination of factors such as general experience, knowledge of the properties, physical inspection, company maintenance policies, past company studies, observed life spans at the company of the same or similar equipment and information gathered throughout the industry. From the ALJ's viewpoint, there is no doubt that Mr. Spanos exercised informed judgment to some degree because of his four depreciation studies and industry experience. However, the problem is how you know that his opinion is correct. Mr. Spanos failed to present anything other than his assertion that his survivor curve analysis is correct. The ALJ finds that there is no way to evaluate Mr. Spanos' conclusions because of the limited information about what the accounts contain. The Interveners' experts testified about what they think is in the accounts, but that testimony did not fix the problem. It only added different forecasts. As a result, the ALJ recommends splitting the difference for the time being and reducing the

depreciation expense by $3.35 million dollars, i.e., half of the $6.7 million dollars requested by Interveners.

6. **Mass Property Net Salvage

OIEC/OER witness Mr. Pous was the only witness to object to OG&E's proposed mass property net salvage rates. Mr. Pous recommended adjustments to four accounts: Account 353 (Transmission Station Equipment), Account 355 (Transmission Poles and Fixtures), Account 390 (Structures and Improvements) and Account 393 (Transportation Vehicles). (Pous Responsive Testimony p. 82, ln. 5-18.) If adopted, Mr. Pous' adjustments would reduce the depreciation expense by $5,574,257 dollars.

For Account 353 (Transmission Station Equipment), Mr. Pous proposes a -10% net salvage value compared with Mr. Spanos' -30% net salvage value. The ALJ finds that OG&E's historical data shows the overall net salvage value for Account No. 353 is -58%, even though the Commission approved a previous estimate of -25%. As a result, the ALJ finds that Mr. Spanos' value of -30% is the appropriate percentage, and the ALJ will not reduce the depreciation expense by $2,425,404.

For Account 355 (Transmission Poles and Fixtures), Mr. Pous proposed -50%, while Mr. Spanos proposes -60%. (Pous, Direct Testimony p. 82,l n 13-1.) Account 355 is a difficult account, because it contains wood and steel poles with different life spans. Most pole or conductor retirements are due to retirement forces that occur prior to the useful life of those assets. Such transactions generally also do not reflect the concept of economies of scale. In the future when larger portions of the system are retired on a planned and contiguous basis, the per-unit cost of removal should be used. Meanwhile, Mr. Pous contends that current levels of net salvage being recorded by OG&E may reflect abnormal and unusual levels of complexity as well as individual and inefficient retirement of assets compared to what will transpire in the future. The ALJ finds that the Commission should adopt OG&E's historical averages rather than speculate about future savings. As a result, the ALJ will not reduce depreciation on this account by $1,670,348 dollars.

For Account 390 (Structures and Improvements), Mr. Pous recommends a positive 15% net salvage value, while Mr. Spanos recommended zero percent. Mr. Pous assumes that OG&E will be able to profit from the sale of buildings in this account. However, the overall average net salvage value for Account 390 is one percent and the five-year average is zero. (Spanos

Rebuttal, p. 43, ln 6-9 and Table 2.) Mr. Pous appears to be looking at the potential resale of the land, which is not depreciable. As a result, the ALJ will not reduce the depreciation expense by $833,787 dollars.

For Account 392 (Vehicles and Related Transportation Equipment), OG&E proposes to continue with the existing salvage value of positive ten percent, and Mr. Pous recommends positive 20% for Account 392.1 (cars and trucks), positive 15% for Account 392.5 (heavy trucks) and zero percent for Account 392.6 (trailers). Mr. Spanos used historical averages to keep salvage low. However, Mr. Pous persuasively showed the Kelley Blue Book and NADA publications show higher values. As a result, the ALJ will reduce annual depreciation by $644,718 dollars based on Mr. Pous' testimony.

7. Combined Impact

Based on the foregoing findings, the ALJ finds that the depreciation expense for the test period, i.e., $314,602,372, should be reduced by $18,894,718 dollars, which results in a depreciation expense of $295,707,654 dollars.

I. Acquisition Adjustments

An acquisition adjustment is the difference between the purchase price of an asset and its original cost. The *pro forma* adjustment here relates to the acquisition adjustment for the Redbud Power Plant. This amortization is the equivalent of depreciation expense for the acquisition premium associated with the plant purchase. This adjustment increases operating expense by $5,567,337. No one contested that adjustment, and so, the ALJ approves it.

J. SPP and Transmission Expense

1. Southwest Power Pool Expense

OG&E proposes an increase in operating expenses in the amount of $628,295 for the SPP administration fee, the FERCassessment fee, the SPP annual fee, and the North American Electric Reliability Corporation annual fee. The adjustment is based upon updated SPP Schedules 1, 1-A, 9, 12, and actual expenses for calendar year 2015. No one opposed this expense. The ALJ approves this expense.

2. SPP Cost Tracker

OG&E proposes to remove SPP expenses that are recovered outside of base rates through its SPP Cost Tracker. These are Schedule 1 third-party, non-affiliate costs. The proposal would also remove SPP costs recovered directly from certain customers. This adjustment is based on

actual costs for the test year derived from the SPP Revenue Requirement and Rates file. The ALJ finds that OG&E's adjustment should be approved.

3. Transmission Expenses

OG&E adjusted transmission expenses recovered from LSE. The adjustment is a decrease of $33,006,737 and was calculated from the FERC Transmission Formula Rate True-Up Adjustment for 2014. The adjustment reduces transmission operations and maintenance expense, depreciation expense, administrative and general expense and taxes other than income recovered from LSEs. The ALJ finds that OG&E's adjustment should be approved.

4. Intracompany SPP Expenses

OG&E proposes to remove expenses in the amount of $125,735,155 received by the Company from SPP for network transmission service provided by OG&E. These expenses are based upon actual amounts for the test period. The ALJ finds that OG&E's adjustment should be approved.

K. Rider and Tracker Modifications

1. Extension of the Southwest Power Pool Cost Tracker

OG&E proposes to extend the ("SPPCT"), approved by Commission Order No. 583894 in Cause No. PUD 201000146. The SPPCT recovers costs associated with transmission projects and facilities that have been approved by the SPP in its regional planning processes and constructed by non-OG&E transmission owners throughout the SPP, and SPPCT also recovers costs allocated to OG&E through FERC-approved transmission rates ("Third Party Owned Transmission Costs"). No costs recovered in the SPPCT are related to any projects constructed and owned by OG&E. OG&E does not earn any return on any Third Party Owned Transmission Costs. The SPPCT simply recovers the actual Third Party Owned Transmission Costs billed to OG&E by the SPP. (Rowlett Rebuttal, p. 2, ln. 22-29.)

OER asks the Commission to discontinue the SPPCT and include in base rates all Third Party Owned Transmission Costs. OER contends that OG&E failed to meet the standards for a rider, namely volatile costs, large enough to present a threat to the financial utility and not reasonably manageable by the utility without a rider. The ALJ disagrees with OER and finds that these costs are volatile; increasing by $50 million over a five-year period (Rowlett Rebuttal, p. 5. ln. 4 through p. 6, ln. 2); that the increase in these Third Party Owned Transmission Costs in 2015 was $9 million, which was more than twice the overall rate increase that OG&E received in

its last general rate case; and that without a tracker like the SPPCT, cost increases for these Third Party Transmission Costs that occur between rate cases would be lost and not recoverable. *Id.* PUD agreed that the continuation of the SPPCT was appropriate. (Chaplin Responsive, p. 15, line 20-21.) The ALJ finds that extension of the SPPCT is reasonable and recommends that the Commission approve it with the condition that no costs for OG&E projects are to be included in the SPPCT.

However, PUD proposes that language be added to the SPPCT tariff that would allow "broader" review of new factors in the event any annual adjustment exceeds 50% as compared to the previous year. (Chaplin Responsive, p. 15, ln. 20 through p. 16, ln. 8.) In response, OG&E proposes the following language to facilitate PUD's review if a significant increase in cost occurs.

> If the annual increase in the SPP expenses, designated as (A) in the formula above, increased by more than 50%, the Company shall provide a detailed narrative of the causes of the increase in the SPP Schedule 11 tariff. (Rowlett Rebuttal, p. 3, ln. 22-25).

The ALJ finds that the current SPPCT requires "the Company to submit a set of work papers sufficient to document the calculations of the re-determined SPPCT rates with each annual re-determination." (Rowlett Rebuttal, p. 3, ln. 26-28.) As a result, the ALJ recommends that the SPPCT be extended and amended with OG&E's suggested language.

2. Fuel Adjustment Clause Issues

OG&E proposes to move from base rates to the FAC air quality control systems consumable costs ("AQCS") and the wind production tax credits certain costs/credits ("PTCs"). The Commission rejected OG&E's AQCS argument in Order No. 647346, effective December 2, 2015, issued in Cause No. 201400229, where the Commission adopted the current ALJ's recommendation on that issue. Presently, the ALJ rejects OG&E's reiteration of its AQCS argument based on that prior ruling but suggests that OG&E apply for a rider.

With respect to the PTCs, the ALJ submits that OG&E needs to apply for either a rider or a regulatory asset. OG&E contends that it needs FAC treatment to avoid annual rate cases to pass PTC savings to its customers. From the ALJ's perspective, the source of the problem is that if the Commission keeps the PTCs in base rates during the test period, then expiring PTCs later require OG&E to make up the difference from other revenues between rate cases. The PTCs start to expire in 2017, which is not an immediate problem given a proposed 2017 rate case. In

the near term, OG&E's proposal is revenue neutral to OG&E and to its customers. It is an approximately $57,000,000 increase in base tariffs that becomes a $57,000,000 reduction in the FAC. However, there will be additional costs to the consumers as the PTCs expire. (Thompson, Responsive Testimony, p. 26, ln. 16-19.) Consequently, moving the PTCs to the FAC is not a good deal for ratepayers in the long run. If OG&E does not want to file annual rate cases, PUD suggests that OG&E apply for either a rider or regulatory asset. (Thompson, Responsive Testimony, p. 27, ln. 1-3.) The ALJ adopts PUD's recommendation.

3. Elimination and Consolidation of Riders

OG&E has twelve riders and proposes to eliminate six.

Table 8

System Hardening Program Rider ("SHPR"	Eliminate
Security Rider ("SR")	Eliminate
SmartGrid Rider	Eliminate
Crossroads Rider	Eliminate
Southwest Power Pool Transmission System Additions ("STSA")	Eliminate
Renewable Transmission System Additions ("RTSA")	Eliminate

Five of these riders are no longer needed because the costs included in these riders are being incorporated into base rates. In addition, certain elements of the Crossroads Rider and Renewable Transmission System Addition ("RTSA") are being distributed to other riders. The RTSA rider is comprised of five components: the Renewable Transmission Surcharge ("RTS"), the Southwest Power Pool Transmission Revenue ("SPPTR"), the Transmission Service Revenue Credits ("TSRC"), the New Renewable Energy Credit ("NREC"), and the GPWRR. OG&E proposes to pass the credits associated with SPPTR and TSRC through the SPPCT. (Cash, Direct Testimony, p. 17, ln. 1-5.) The ALJ finds that proposal to be appropriate, because the SPPCT is already a means of tracking certain expenses and credits associated with the SPP transmission system.

The revenues from subscribed Renewable Energy Credit ("REC") sales and Green Power Wind Rider sales are currently credited back to OG&E's retail customers through RTSA rider via NREC and GPWRR components, the Crossroads rider and the FAC. OG&E proposes to

pass the credits associated with the NREC and GPWRR through the FAC. (Cash, Direct Testimony, p. 17.) PUD agreed with OG&E's recommendations for passing these REC and wind energy revenues through the FAC and the RTSA components through the SPPCT. (Chaplin, Responsive Testimony, p. 16, ln. 13-21.) Meanwhile, OER recommends terminating the SPPCT, but did not provide an alternative proposal for passing the RTSA credits through to customers. No other party opposes OG&E's above-described proposals for eliminating and consolidating riders. The ALJ rejects OER's proposal to terminate the SPPCT and finds that the other parties' proposals are reasonable and should be approved.

4. Removal of Expenses Included in Riders

OG&E made several adjustments to test period expense for costs associated with riders and trackers. First, the Company removed costs from the test period related to the Oklahoma Demand Program Rider ("DPR") and the Arkansas Energy Efficiency Cost Recovery Rider. These costs are recovered through ongoing rider mechanisms and should therefore be removed from base rates. This adjustment decreases O&M by $24,851,709. (Thenmadathil Direct, p. 12, ln. 22-25.) No party opposes this adjustment, and the ALJ adopts it.

Second, OG&E made two separate adjustments to remove certain storm related expenses from base rates. OG&E removed all storm amortization expenses included in the test year in the amount of $4,180,798. These storm amortization expenses resulted from prior storm expenses that were deferred to a regulatory asset account and are currently being recovered through the Storm Rider. Also, OG&E reduced the test year level of actual storm expense by $864,564 in order to bring the base rate level of storm expenses back down to $2,739,595. This was the base rate level set in the prior two rate cases, Cause Nos. PUD 200800398 and PUD 201100087. The total adjustment to storm expense is a decrease of $5,045,362. (Thenmadathil Direct, p. 13, ln. 16-23.) No party opposes this adjustment, and the ALJ adopts it.

Third, OG&E removed certain SPP costs that are recovered outside of base rates. Third Party Owned Transmission Costs and included in SPP Schedule 11 Base Plan Fees that are currently being recovered through the SPPCT were removed since these costs are recovered through the SPPCT. This results in a decrease to O&M of $38,870,067. Also, SPP fees directly charged to certain customers were also removed, which amounts to $474,235. The total *pro forma* adjustment is a decrease of $39,344,302. (Thenmadathil Direct, p. 15, ln. 13-18.) With the exception of OER, which advocated for the discontinuance of the SPPCT and the inclusion of

Third Party Owned Transmission Costs in base rates, no other party opposes this adjustment, and the ALJ adopts it.

Finally, OG&E removed all fuel and purchased power costs from the test period, with the exception of cogeneration capacity payments related to cogeneration contracts with AES and Oklahoma Cogeneration. OG&E proposes removing all fuel expenses from the test year (except capacity payments) and including those costs in the FAC rider. This adjustment removes $860,548,419 from operating expenses while leaving $82,755,933 in base rates for the cogeneration capacity payments. (Thenmadathil Direct, p. 16, ln. 6-11.) No party opposed this adjustment, and the ALJ adopts it.

L. Environmental Compliance Plan

OG&E asks the Commission to approve a regulatory asset for Low NOx burner installations and Activated Carbon Injection systems ("ACI") at two of OG&E's Seminole generating units. The burner systems will be placed in service in 2017 at the earliest at an estimated cost of $99 million dollars. OG&E will complete the ACI systems in 2016 at a cost of $24.3 million dollars. OG&E wants regulatory asset treatment to recover depreciation and O&M costs from the start of service until inclusion of the assets in rate base at the next rate case. OIEC/OER and the AG object for several reasons: OG&E failed to provide annual depreciation and operating cost estimates[15]; the new assets do not meet the criteria for a regulatory asset[16]; completion of the assets will occur outside of the test period; and, there is no reason to treat these assets different from other capital assets placed in service between rate cases.[17] The ALJ finds that the Commission need not consider OG&E's request at this time, because start of service will occur after the test period in this cause, and OG&E has an adequate remedy, which is an application for emergency order in the next rate case scheduled by OG&E to occur in 2017.

M. Regulatory Expenses

1. Outside Services

OG&E acknowledges an error regarding outside services, specifically related to certain legal service costs. In response to a question arising from PUD's audit of OG&E's books and records, OG&E discovered that OG&E Shareholders' legal fees were included in the cost-of-service. Since the OG&E Shareholders is a shareholder advocacy group, all legal fees associated

[15] Daniel, Responsive Testimony, p. 10, ln. 24-28, p. 11, ln 1-2.
[16] Farrar, Responsive Testimony, p. 8, ln 15-19.
[17] Daniel, Responsive Testimony p. 5, ln 6-8.

with this group should be removed from customer expenses and assigned to the shareholders. The amount of these legal fees accidentally included in the cost-of-service was $275,725. In addition, $20,063 of legal fees associated with legislative advocacy should also be removed. In total, OG&E testified that $295,788 should be removed from the test year. (Thenmadathil Rebuttal, p. 8, ln. 17-25.) The ALJ finds that the foregoing costs for outside services should be removed from the cost-of-service and that OG&E should implement accounting procedures to ensure that such costs are excluded from the test year in future general rate proceedings. The ALJ recommends adopting of OG&E's adjustment in the amount of $295,788.

With respect to any improper collection for such services under prior rate orders, the money was collected under lawful orders, and the Settled Rate Doctrine should apply meaning that the Commission should not revisit those expenses.

2. Rate Case Expenses

OG&E's Application included a *pro forma* adjustment for estimated rate case expenses for this rate case. OG&E estimated total rate case expenses at $1,160,000. OG&E proposes to amortize that expense over the first two years new rates are in effect, thus resulting in a *pro forma* adjustment of $580,000. (Thenmadathil Direct, p. 17 ln 22-25.) The dispute over rate case expense is twofold: (1) witness training fees and (2) how to address known and unknown expenses arising after the full evidentiary hearing. PUD objected to $132,492 for witness training, contending that such training may benefit the Company, but it does not benefit OG&E's customers. (Patel Responsive, p. 11-13.) OIEC/OER also opposed the witness training expense, contending that paying $132,492 was excessive. (Tr. Late P.M. 5/25/2016, p. 29-30.) During the trial, Counsel for OIEC offered a copy of an inexpensive witness training video to show that $132,492 dollars for witness training was excessive. In response, OG&E contends that witness training is an integral part of training for an employee who must appear in regulatory proceedings and that shareholders, customers and regulators all benefit when a company witness with technical skills is trained in understanding and responding to issues raised in the regulatory process. (Thenmadathil Rebuttal, p. 4.) The ALJ finds that the $132.492 for witness training was unnecessary and overly expensive: All OG&E witnesses were expert witnesses, and demeanor is only relevant for a lay witness. Next, OG&E only had four witnesses who had not previously testified in a rate proceeding. There was no apparent need to train more than four people with an outside trainer. Furthermore, most of the record is built around pre-filed

testimony, and in-house counsel for OG&E should have been able to prepare all of their witnesses for the courtroom testimony involved. Consequently, the ALJ recommends that the Commission deny the witness training expense of $132,492 dollars.

On May 24, 2016, OG&E filed updates to AG DR 2-7, which includes a list of actual rate case expenses incurred as of April 30, 2016, and supporting documentation. (Trial Exhibits Nos. 85 and 86, respectively.) Those expenses totaled $766,855 dollars, and OG&E proposes a resulting two-year amortization resulting in $383,428 annually. For expenses incurred after April 30, 2016, OG&E proposes a regulatory asset subject to review in its next rate case. (Trial Exhibit No. 85.) OIEC/OER recommends that "reasonable" expenses incurred as of April 30, 2016, be recovered over a two-year period and that recovery of any costs subsequent to that date be considered in OG&E's next rate case. (Tr. Late P.M. 5/25/2016, p. 31.)

The ALJ finds that OG&E's proposal to record rate case costs incurred after April 30, 2016, as a regulatory asset and amortize those costs over the first two years' rates is reasonable. Therefore, the ALJ recommends that the Commission presently allow recovery of $634,363, with a two-year amortization of 317,181.50 annually for expense incurred on or before April 30, 2016. In addition, the ALJ finds that any rate case related expenses incurred after April 30, 2016, should be treated as a regulatory asset subject to review and recovery in the next general rate case.

3. Other Regulatory Expenses

OG&E proposes an adjustment to regulatory expense exclusive of rate case expenses. This adjustment is the result of three adjustments. First, the Company normalized regulatory costs using a two-year average for various expenses in the Oklahoma jurisdiction excluding rate cases. This normalized cost includes costs related to the Company's regulatory costs associated with Cause No. PUD 201400229. This normalization reduced operating expenses by $528,761. Second, OG&E removed the Annual Public Utility Assessment Fee ("APUAF") in the amount of $2,233,319, since the APUAF fee is already recovered through a surcharge on customer's bills. Finally, any remaining amortization related to rate case expenses from the prior rate case was also removed. This results in a decrease of $28,337 for the third adjustment. The total for all three adjustments results in a decrease of test year regulatory expense of $2,790,417. (Thenmadathil Direct, p. 12, ln. 28 through p. 13, ln. 4.)

PUD made two adjustments to OG&E's regulatory expense total. First, PUD removed costs associated with this current proceeding. (Thenmadathil Rebuttal, p. 4, ln. 24-25.) PUD contends that OG&E erred in including the costs of this proceeding in both rate case expense and regulatory expense. In rebuttal testimony, OG&E acknowledged this error and removed all costs associated with the current proceeding from the regulatory expense balance.

PUD also removed costs associated with OG&E's environmental compliance proceeding in Cause No. PUD 201400229. (Thenmadathil Rebuttal, p. 4, ln. 28-19.) OG&E contends that PUD failed to present a reason for that reduction, but the ALJ is familiar with PUD's problem, because the ALJ heard the 201400229 case. To the ALJ, the problem is that PUD contracted for consultant services (Dr. Roach) based on final approval or denial of all projects covered by the 201400229 application. When the Commission denied relief, OG&E decided to refile under separate applications. Consequently, we are not done with all projects. Thus, the ALJ recommends that the Commission pay the AG's final witness fees, if any, in Cause No. PUD 201400229 and wait for final resolution of the other projects before closing the books on PUD's witness fees in Cause No. PUD 201400229.

XII. COST–OF-SERVICE

A. Classification of FERC Accounts 364-368

The AG's witness Mr. Daniel and ASC's witness M. Garrett took issue with OG&E's classification of FERC Accounts 364-368. They recommended that those accounts be classified as one-hundred percent demand related. In response, the ALJ adopts OG&E's rebuttal by Mr. Smith, who stated that classifying these accounts as both demand and customer related is consistent with NARUC's *Cost Allocation Manual* and prior Commission practice.

B. Zero-Intercept Study

PUD's witness Mr. Schwartz stated the OG&E's zero-intercept study used in the last two rate cases is out-of-date because of increased investment in the distribution system. OG&E's witness Mr. Smith contended that unit costs remained unchanged, but OG&E agreed to perform a new zero-intercept study for the next rate case. The ALJ finds that the Commission should use the existing zero-cost study.

C. Unit Cost Calculations

FEA's witness Mr. Gorman recommended that the demand charge for LPL-TOU SL-1 should be reduced by $0.60 per kW to reflect the difference in cost between SL-1 and SL-

2. Mr. Gorman contends that the demand unit ratio used in the Cost-of-Service Study ("COSS") should be the same as the demand unit ratio of the billing determinants used in OG&E's proof of revenue statement. (Gorman, Responsive Testimony, p. 15, ln. 8 through p.17, ln. 10.) OG&E presented rebuttal through OG&E witness Mr. Wai. (Wai, Rebuttal, p. 7, ln. 24 through p. 8 ln. 19.) The ALJ finds that OG&E's billing and calculations are correct and the changes recommended by Mr. Gorman are unnecessary.

XIII. RATE DESIGN

The first step in the rate design process is to allocate the revenue requirement derived from the COSS (Scott Direct, p. 3, ln. 22-23). The primary goal of OG&E's revenue allocation is to set each class' revenue requirement as close as possible to the actual cost to serve that class. (Scott Direct, p. 17, ln. 5-7)

Once the revenue allocation process was completed, OG&E's next step was to design rates for each class that would collect the revenue share allocated to that class. Rates were allegedly designed to incorporate the change in rates that ensure revenues match the deficiency or surplus defined within the revenue allocation process. The major steps of OG&E's rate design process included determination of the unit costs for each rate class, application of the unit costs and marginal costs to create initial price levels, and determination of rate structure and final rates through an iterative process to ensure proper recovery of revenue requirements (Wai Direct, p. 4, ln. 26-30).

OG&E proposes two general structural changes to its current rates. These are 1) incorporation of a kW demand charge for non-demand non-time-variable tariffs, and 2) changes to the season definitions for the Standard Residential (R-1) tariff so as to eliminate separate rates for the shoulder months (Wai Direct, p. 7, ln. 1-3).

A. Non-unanimous Stipulation

1. On May 23, 2016, parties to the OG&E rate case (Cause No. PUD 201500273) filed a non-unanimous stipulation and settlement agreement resolving certain rate design, cost-of-service and Fuel Adjustment Clause issues. All parties to the cause, with the exception of OG&E and the OG&E Shareholders, signed the settlement agreement as a compromise.

2. The Stipulating Parties are: PUD; AG; OIEC; Wal-Mart/Sam's; AARP; OSN; ASC; OHA; Wind Coalition; OER; FEA; Sierra Club, and CPN.

3. Several of the intervening parties, including PUD, AG, OIEC, OER, Sierra Club, Wal-Mart/Sam's, ASC, OHA, and the CPN, in addition to signing the stipulation, presented either live testimony, a proposed Report of the Administrative Law Judge, or some combination thereof in support of the Joint Stipulation.

4. The Joint Stipulation contains 13 sections, some with multiple subsections, with Section 12 being General Reservations and Section 13 being the Non-Severability Clause.

5. On May 25, 2016, OG&E filed a red line Response to the Joint Settlement.

6. After a recess to allow the Stipulating Parties to caucus, PUD witness Kathy Champion presented live testimony in summarizing the Joint Stipulating Parties' position on the OG&E response.

7. Section 1 of the Joint Stipulation states that no new demand charge shall be implemented for any customer class or subclass not currently paying a demand charge and that before implementing any new demand charge for any rate class not subject to a demand charge OG&E shall conduct a pilot program to evaluate customer acceptance, understanding and ability to respond to a rate design containing demand charges.

8. Section 2 addresses the Monthly Customer Charge currently at $13 for residential ratepayers. In the original application, OG&E proposed raising that to $26.40. The Joint Stipulation would hold the customer charge at $13. The OG&E response seeks to compromise at $20 for residential and $30 for general service, excluding public schools, oil and gas and municipal pumping.

9. Section 3 of the Joint Stipulation states current rate schedules available to distributed generation customers shall continue to be available without demand charges. OG&E sought to require that distributed generation residential and small commercial customers using some of their output to serve onsite load be required to subscribe to a specified time of use rate with attached demand charges.

10. In live testimony on May 25, 2016, Witness Champion testified that the Stipulating Parties reject the proposed OG&E changes to Sections 1 thru 3 as not being clean-up language but, rather, proposing substantive changes.

11. Section 4 for the Joint Stipulation deals with revenue allocation. In the case of a revenue decrease any customer class with a Relative Rate of Return ("RROR") less or greater than 1 will move to 1 through a two-step process. Any remaining revenue will go to reduce rates

of the residential class. In case of an increase, any customer class with an RROR less than 1 will move 25 percent closer to 1. The revenue increases associated with this move will be redistributed proportionately to rate classes with an RROR greater than 1. In Step 2, with the exception of Public Schools, all General Service (small to medium sized Commercial), Power and Light and LPL with an RROR of less than 1 shall move the remaining 75 Percent to 1. The amount eliminated in this step will be redistributed to the General Service, Power and Light, Oil and Gas Production and LPL customer classes with an RROR greater than 1. Any revenue increases or decreases to LPL service levels 1 thru 4 shall be distributed on an equal percentage basis to these service levels.

12. OG&E did not propose any changes to Section 4.

13. The Stipulating Parties did not accept OG&E's proposed change to Section 5 on Miscellaneous Charges which sought to increase the proposed Service Initiation Fee from $17.50 to $22.50.

14. The Stipulating Parties would accept the OG&E wording changes in Sections 6 and 7 pertaining to the PayGo Prepay Billing Option or the Smart Meter Opt Out Option, but noted that same language needed to also be included in the Company's tariff.

15. OG&E did not propose any changes to Sections 8, 9 and 10 of the Joint Stipulation dealing with the Zero Intercept Study, Power and Light time of use rate design, and LPL time of use rate design.

16. In Section 11, the Stipulating Parties did not object to the OG&E amending language that would make a reduction in the fuel factor become effective sooner rather than waiting until 30 days after Commission approval of the Joint Stipulation.

17. Likewise, the Stipulating Parties did not object to OG&E's proposed amended language to the terms and conditions on PayGo.

B. Differences Between Parties

1. Stipulating Parties and OG&E agree to no new demand charges for customer classes currently without a demand charge until a pilot program is conducted. However, the Stipulating Parties object to OG&E's additional requirements.

2. OG&E would increase customer charge to $20/month. Stipulating Parties would leave it as $13/month.

3. Stipulating Parties object to OG&E wording requiring a demand charge for residential and small commercial distributed generation customers who use some power and sell the rest to the utility.

4. Stipulating Parties set Service Initiation Fee at $17.50, OG&E at $22.50.

C. ALJ's Observations on OG&E's Proposed Structural Changes to Residential Rates and Charges

While a utility's authorized profits are based on its rate base and authorized ROR, actual profits between rate cases are the difference between collected revenues and costs. Profit achievement is driven by revenue collection largely based on volumetric, commodity sales (*i.e.*, $/kWh) and demand (*i.e.*, $/kW). There are two fundamental aspects of profit achievement under cost-of-service regulation. First, the utility's actual costs may deviate from the revenue requirement established in the rate case. Second, utility collected revenues may not equal the revenue requirement (in fact, they rarely–if ever do). Actual collected revenues are based on incurred billing determinant levels in a given year (i.e., sales, customer count, and demand), which may be different from those used in the test year. Therefore, utility profit achievement is also driven by changes in billing determinants, and these may be factors outside the utility's control, such as the number of customers in the service territory and their particular consumption levels, which are strongly influenced by macroeconomic facts, such as employment and income. The largest component of collected revenues comes from volumetric sales. Thus, any decrease in sales between rate cases due to economic conditions, weather, or energy conservation negatively impacts utility profitability.

The ALJ submits that the Commission should consider adopting ratemaking mechanisms that are intended to make the utility indifferent to resources that negatively impact revenue collection between rate cases. Such ratemaking approaches better align the utility's business model with public policy goals for increased energy efficiency and distributed energy resource ("DER") deployments. In that regard, the Commissioners have previously rejected performance based ratemaking for electric utilities as well as decoupling. However, the Commission did approve a lost revenue adjustment mechanism for the DPR, but the end result of strict adherence to traditional cost-of-service regulation is that OG&E now wants its default residential plan to consist of a high customer charge, a demand charge and a volumetric energy charge in addition to the customer's fuel cost. With a high fixed charge, the utility recovers more, or all, of its fixed costs through a non-volumetric charge. Here, OG&E wants the user to pay for his share of

distribution costs, regardless of what he consumes. The variable demand charge would cover the customer's share transmission, based on his peak consumption. By adding a high fixed customer charge and a demand charge, the variable, volumetric energy charge, should drop, since the volumetric energy charge currently cover the T&D costs.

Even at OG&E's compromise level of twenty dollars, the proposed customer charge would be one of the highest customer charges in the nation. In looking at high fixed charge disputes in other states, there is no consensus on what are fixed charges for distribution. The Commission is being asked by OG&E to accept Mr. Wai's testimony about what are the fixed costs of distribution. However, OG&E's need for a seven dollar per month increase in the residential customer charge is based on fixed costs that only OG&E Shareholders agreed to.

Next, the ALJ studied the massive public comment file in this cause. The complaints center on using rate design to increase rates without a change in either customer consumption or the utility's revenue requirement, and it was also apparent from the public comments that many commenters do not understand how their monthly bills would be calculated under the new program and that they generally did not understand either how their current bill is calculated or how to save money under any of OG&E's existing plans. Based on the public comments, the ALJ recommends a pilot program and customer education before general implementation of major structural changes in rates, even though OG&E's witness Dr. Faruqui testified that a pilot program is not needed.

Under OG&E's Variable Peak Pricing Plan ("VPP") the customer saves money by staggering use of major appliances, which is a key to saving money under a residential demand charge. OG&E's witness Dr. Faruqui testified that a residential demand charge is based on intensity of consumption during a fifteen minute period rather than system peak or overall consumption during the billing period. Consequently, the customers need to learn not to run major appliances at the same time.

The ALJ submits that the demand charge concept may be difficult for some customers to understand. So, the ALJ suggests a simpler alternative in the form of a "minimum bill" that guarantees the utility a minimum amount of revenue from each customer. Instead of that amount billed as a fixed customer charge, customers pay a volumetric rate and the bill is effectively trued-up to ensure that each customer is paying the minimum amount. This approach preserves

the incentive for energy conservation as the customer continues to face a volumetric charge without a high fixed customer charge. (*See* Lazar, 2014.)

D. Distributed Generation

OG&E originally proposed two separate rate classes for Distributed Generation ("DG") customers taking service after November 1, 2014. The new classes are the R-TOU-kW for residential customers and the COM-TOU-kW for Commercial customers that heretofore were not being served by rate schedules that included demand charges in their current rate schedules. OG&E also requested that companion tariffs of Net Energy Billing Option- kilowatt and the Renewable Power Purchase Option should also be approved.

The proposed R-TOU-kW and COM-TOU-kW rate schedules would consist of a three part rate structure to include: 1) a demand charge to recover the Transmission and Distribution costs (wires) of providing service to customers; 2) time-differentiated energy charges which collect variable costs and portions of production costs; and 3) customer charges that capture customer costs associated with providing customer related costs to each individual customer. OG&E's proposed demand charge for the R-TOU-kW was $1.78/kW and for COM-TOU-kW was $3.94 (Wai Direct, p. 27, Table 14).

OG&E witness Mr. Wai proposed prices of the R-TOU-kW and COM-TOU-kW DG tariffs established at underlying functional costs for each of these proposed new DG classes of service. (Wai, Direct Testimony, p. 26, l. 16-18.) Mr. Wai further showed in his Direct Testimony (by comparing Table 5 and Table 14) that billing DG customers under the DG rates originally proposed by OG&E (R-TOU-kW and COM-TOU-kW; Table 14) would generally result in lower bills than under OG&E's proposed standard TOU rates (Table 5).

The ALJ finds that at this time, DG has nominal impact on OG&E's ability to provide the optimum price mix to its customers, that DG does not stress OG&E's substations, and that OG&E can recover its distribution costs without special rates and charges for DG. The ALJ recommends that the Commission adopt the DG position in the Joint Stipulation as last amended.

E. Miscellaneous Charges

On the issue of miscellaneous charges, the Stipulating Parties requested that the Commission order the following charges: reconnection fee of $21.00, service initiation fee of $17.50, and meter test fee of $75.00 (Joint Stipulation, Section 5, p. 6).

OG&E originally proposed to reduce the reconnection fee from $35.00 to $26.00, reduce the Service Initiation fee from $25.00 to $22.50, and increase the Meter Testing fee from $50.00 to $95.00. OG&E's proposed fees were strictly based on the costs associated with providing those services and those costs were amply supported in the record. During the hearing and in reaction to the Joint Stipulation, OG&E Witness Mr. Rowlett believed that having the Service Initiation Fee be $22.50 reflects the costs in the call center to handle service initiation requests. (Tr. P.M. 5/26/2016, p. sd-27, ln. 1-9.) While OG&E believes its proposed reconnection and meter test fees are correct and accurately based on the cost of those services, OG&E agreed not to challenge the reconnection and meter test fee levels proposed by the Stipulating Parties. (*See* OG&E's Response to the Stipulation; Tr. P.M. 5/26/2016, p. sd-27, ln. 10-23.) The ALJ finds that the Service Initiation Fee should reflect actual costs and adopts the proposed fee of $22.50. Since OG&E does not challenge the reconnection and meter test fee levels proposed by the Stipulating Parties, the ALJ accepts those fees as stated in Section 5 of the Joint Stipulation.

F. PayGo Optional Tariff

The Stipulating Parties recommended certain reporting and operational requirements for OG&E's PayGo Prepay optional billing program ("PayGo"). (Joint Stipulation, Section 6, p. 6.) PayGo offers customers the choice of using the security deposit to pre-pay for electricity when initiating service. If service gets discontinued for non-payment, the customer can re-establish service by depositing more funds into their account. (Scott Direct, p. 13, ln. 7-13.) PayGo is a bill payment option, not a pricing plan. Participants may generally choose from any pricing plan available; some alternatives, such as net metering tariffs, are not immediately available due to the added billing support complexity. OG&E is offering this bill payment option as a voluntary alternative. (Scott Direct, p. 7, ln. 17-20.) The Stipulating Parties accepted OG&E's Paygo option subject to tariff modifications (Joint Stipulation, Attachment A). Second, the Stipulating Parties request inclusion of annual reporting of program costs and savings, customer disconnections, participation and customer income status. (Joint Stipulation, page 6, Section 6(b).) Third, the Stipulating Parties recommend that OG&E obtain the customer's acknowledgment of certain information prior to enrollment in the PayGo program (Joint Stipulation, page 7, Section 6(c)).

OG&E considered the Stipulating Parties modifications to the PayGo program in its Response to the Joint Stipulation. OG&E made minor modifications to the Joint Stipulation

clarifying the PayGo program and terms of service (Tr. P.M. 5/26/2016, p. sd-27, ln. 24 through p. sd-28, ln. 25).

The ALJ finds that the PayGo Prepay Billing Option settlement provision contained in Section 6 of the Joint Stipulation, as amended by OG&E in its Response to the Joint Stipulation, is reasonable and should be adopted.

G. Automated Metering (Smart Meter) Opt Out

The Stipulating Parties recommend approval of OG&E's automated metering opt out tariff. (Joint Stipulation, Section 7, p. 7.) In that regard, OG&E wants to add the words "Smart Meter" between the words "Automated" and "Opt" in the title and the first sentence of Section 7 of the Joint Stipulation. (Tr. P.M. 5/26/2016, p. sd-29, ln. 2-11.) The ALJ finds that the Advanced Metering (Smart Meter) Opt Out settlement provision contained in Section 7 of the Joint Stipulation, as amended by OG&E in its Response to the Joint Stipulation, is reasonable and should be adopted.

H. Zero Intercept Study

The Stipulating Parties ask the Commission to direct OG&E to perform an updated Zero Intercept study and provide to all parties with the study results as part of its next rate case (Joint Stipulation, Section 8, p. 6). Mr. Rowlett testified that OG&E had no changes to this portion of the Joint Stipulation. (Tr. P.M. 5/26/2016, p. sd-29, ln. 12-13.) In his Rebuttal Testimony, OG&E Witness Smith had already agreed to update the Zero Intercept study for the next general rate case. (Smith Rebuttal, p. 3-4.) The ALJ finds that the settlement provision contained in Section 8 of the Joint Stipulation is reasonable and should be adopted.

I. PL-TOU and LPL-TOU Rate Designs

The Stipulating Parties made two recommendations to the Commission regarding the PL-TOU and LPL-TOU rate design. Regarding the PL-TOU class, the Stipulating Parties requested that any base rate revenue reduction to the class as a result of moving other classes with an RROR below 1 up to a RROR of 1 will be applied first to the winter and off-peak summer energy charges for each service level until such rate are equal with LPL-TOU rates. (Stipulation, Section 9, p. 8.) On the LPL-TOU rate design, the Stipulating Parties propose that for Service Levels 2-5, the Commission implement the demand charges proposed by the Company and be adjusted by the percentage change in revenues that results from the revenue allocation process. In addition, the Stipulating Parties request that the current LPL-TOU demand charge spread of

$0.60/kW between Service Level 1 and 2 be maintained (Joint Stipulation, Section 10, p. 8). OG&E's witness Mr. Rowlett testified that OG&E had no comment to either of these proposals of the Stipulation (Tr. P.M. 5/26/2016, p. sd-29, ln. 14-17). The ALJ finds that the settlement provisions contained in Sections 9 and 10 of the Joint Stipulation are reasonable and should be adopted.

J. Fuel Adjustment Clause

The Stipulating Parties recommend that the approximate $55.1 million balance in the Company FAC be credited back to customers through a credit in the FAC beginning within 30 days after a final order is issued and continuing for 12 months on the same basis that such fuel costs were originally collected (Joint Stipulation, Section 10, p. 8-9). Mr. Rowlett for OG&E did not object to this proposal other than to request the flexibility to return the over-collection faster than the 12 months specified in the Joint Stipulation. (Tr. P.M. 5/26/2016, p. sd-29, ln. 18 through p. sd-30, ln. p 9.) The ALJ finds that the settlement provision contained in Section 11 of the Joint Stipulation is reasonable and should be adopted:

K. Other Rate Structure Changes

OG&E proposes other modifications to its existing R-1 tariff, including the elimination of the Shoulder Season and changes to the Summer and Winter Season rate blocks. As now proposed, the Summer Season will be defined as the revenue months of June through October and the Winter Season will be the months of November through May. OG&E stated that these changes are necessary to make the season definitions of the R-1 tariff consistent with the season definitions of other OG&E tariffs. (Wai Direct, p. 7, ln. 22-29.) PUD agrees with the changes. (Champion Direct, p. 21, ln. 23 through p. 22, ln. 2.) The ALJ finds with OG&E's proposal to eliminate the Shoulder Season and redefine the Winter and Summer Seasons of the R-1 tariff to be appropriate.

L. Other Rate Design Changes

1. Lost Net Revenue

For the DPR Lost Net Revenue ("LNR"), OG&E proposes a reset date of December 31, 2015. (Scott Direct, p. 14, ln. 15-23.) No intervening party disputes OG&E's proposal. The ALJ accepts the reset date for DPR LNR as OG&E proposed.

2. Healthcare Incentive Rate Transition

OHA requested setting the RROR for healthcare facilities to 100% immediately through implementation of the Healthcare Incentive Rate Transition ("HIT") rider, which would reduce General Service ("GS") Rates by 2.6 percent, Power and Light ("PL") Rates by 1.8 percent, and Power and Light – Time of Use ("PL-TOU") Rates by 4.2 percent. OHA also requested adjacent, campus based, multiple Healthcare Facilities accounts (meters) with the same ownership or resident organization to be billed as one customer (Athas and Kelley Responsive, p. 11). OG&E responded that its primary concern was to set each class' revenue requirement as close as possible to a RROR of 100 percent (Scott Rebuttal, p. 14, ln. 4-5). OG&E did not see any recommendation for how or who would pay for the incentives under the HIT rider provided to OHA. (Scott Rebuttal, p. 15, ln. 9-10.) OG&E did not agree with the accounts (meters) aggregation requested by OHA, because OAC 165:35-13-4 requires utilities to individually meter and bill each separate electric consuming facility (building). (Scott Rebuttal, p. 14, ln. 16-21.) The ALJ finds that OHA's requests for the HIT rider and accounts (meters) aggregation are contrary to Commission rules and practice; and they are hereby denied.

3. TOU Critical Peak Pricing

OG&E concluded its TOU Critical Peak Pricing ("TOU-CPP") pilot and proposes to terminate the plan due to declining subscription and increasing popularity of the substitution VPP plan. (Scott Direct, p. 14, ln. 6.) No intervening party disputed the Company's proposal. The Commission adopts the proposal as filed by the Company.

4. Variable Peak Pricing

OG&E proposes making the Variable Peak Pricing ("VPP") program a permanent rate option for the Residential and GS classes, and updating the criteria used to determine the daily on-peak price level for the VPP programs on an annual basis. (Wai Direct, p. 15, ln. 3-7.) No intervening party disputes OG&E's proposal. The ALJ recommends that the Commission adopt that proposed change to the VPP Program.

M. Other Tariff Changes

1. Rate Index

OG&E proposes the addition of a rate index to be inserted at the front of the Terms and Conditions section of the tariffs. See Appendix C. The purpose of this addition is to have a single location at the front of the tariff to make it convenient to locate these fees, changes and

rates. (Cash Direct, p. 14, ln. 14-17.) No intervening party disputes this addition. The ALJ adopts the proposed addition of the rate index.

2. Standard Meter Type

OG&E proposes updating Section 210 of the Terms and Conditions to change the Standard Meter type from mechanical registers to digital registers. (Cash Direct, p. 14, ln. 21-23.) No intervening party disputes this update. The ALJ adopts the re-designation of the Standard Meter type proposed by OG&E.

3. Meter Test Plan

OG&E proposes removing the Meter Test Plan suspension language from section 210 of the Terms and Conditions. This language was added in Cause No. PUD 201100087 and was intended to suspend meter testing during OG&E's SmartGrid deployment. This deployment is complete thereby eliminating the need for the suspension language. (Cash Direct, p. 14, lines 26 – 28) No other party in this proceeding challenged or disputed this update. The ALJ adopts the removal of the Meter Testing Plan suspension language.

XIV. Additional Issues

A. Smart Meter Opt-Out

OG&E proposes two options for the very small number of residential customers that have expressed an interest in either avoiding or limiting usage of smart meters on their homes. (Rowlett Direct, p. 23, ln 12-14.) Under the first option, a customer may request removal of the existing communicating digital meter and instead have OG&E install a non-communicating digital meter on the customer's home. This option is designed to allow customers the choice to pay for manual meter reading. It would require the customer to pay a one-time fee of $115 for upfront costs associated with implementing the "opt-out" for the customer. Such fee would include the cost of the new meter, a restocking fee for the removed smart meter, and the labor costs for the removal of the old meter and installation of the new meter. This fee would also include a portion of the software and accounting costs that are required to manually record, account for and bill under a manual reading system and track eligibility and participation. The customer would get a credit for the cost of any smart meter that can be restocked and placed back into inventory. (*Id.* at p. 23, ln. 14-27.) In addition, this first option would require OG&E to charge a monthly fee of $15.66 per month to manually read the meter in lieu of using the smart meter. (*Id.* at p. 24, ln. 7.)

OG&E also proposes a second option for customers who prefer to keep their communicating digital meter, but limit overall meter communications and eliminate the transmission of usage data through the smart grid network. These are customers who would prefer to preserve the smart-meter enabled outage restoration benefits, and other operational benefits. For example, retaining the smart meter would allow customers to receive alarms and signals from OG&E operations, benefit from enhanced outage restoration timing, and have timely remote connect/disconnect service. This option would eliminate remote meter reading and limit customer-specific usage data from being sent back to OG&E on the smart grid communications network. Because this option would leave the existing smart meter in place, the upfront fee to implement this option would only be $84 for the portion of the software and accounting costs that are required to manually record, account for and bill under a manual reading system and track eligibility and participation. Since OG&E would still require a truck roll to manually read the meter, OG&E would institute the same quarterly process discussed above for the first option. The monthly fee for this second option would also be $15.66. (*Id.* at p. 24, ln. 10-24.).

No party opposes these two smart meter options. The ALJ recommends that the Commission adopt OG&E smart meter opt out proposal.

B. Other Tariff Proposals

Except as otherwise modified or addressed within this report, all other changes to OG&E's tariff, as proposed by OG&E and reflected in Schedule N, and unopposed by the intervening parties, shall be accepted.

C. Wholesale Contract Expiration

As described by OG&E witness Rowlett, in June 2015, OG&E terminated the last remaining wholesale contract, an agreement with Arkansas Valley Electric Cooperative Corporation ("AVEC"), which represented 229 MW of wholesale load. (Rowlett Direct, p. 10, ln. 21-24.) The wholesale contracts were supplied by using a portion of the Company's existing coal, natural gas and wind resources. The embedded cost of generation that was previously allocated to the wholesale jurisdiction is about $283 per kW and any new generation would be significantly more expensive to acquire (*Id.* at p. 11, ln. 1-7). For example, the cost of new combined cycle ("CC") generation is estimated to be approximately $1,250 per kW (*Id.* at p. 11, ln. 7-8). No party disagrees with OG&E's position that the portion of the Company's generation

assets previously allocated to wholesale customers is currently used and useful for Oklahoma retail customers. However, the AG contends that going forward, retail customers should not be subject to recovery of certain expenses associated with these assets, including capital expenses identified in OG&E's Condition Assessment Study, environmental compliance capital projects and new O&M expenses associated with these environmental compliance projects, or any retirement costs. The ALJ finds that OG&E's retail customers benefit from the use of this generating capacity previously allocated to the wholesale jurisdiction. The addition of this generation to serve the Company's retail load will delay the need for OG&E to build or purchase generation capacity in the future that would be more expensive to OG&E's customers. The AG failed to show that the benefits associated with the asset reallocation are outweighed by the risk of future costs. Therefore, the ALJ approves the transfer.

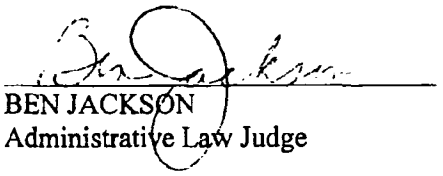
XV. Final Recommendation

Appendix C to this report contains tables summarizing the positions of the Applicant, Respondents and the ALJ, on the revenue requirement and revenue deficiency. Table 9 below summarizes the ALJ's final recommendations on revenue requirement and revenue deficiency.

Table 9

	ALJ
Rate Base	$4,152.329.406
Adjusted Rate Base	$4,198,347,364
Relative Rate of Return (RROR)	7.88%
Adjusted Operating Expense (Including Depreciation)	$801,945,164
Adjusted Income Tax	$77,651,086
Adjusted Revenue Requirement	$1,210,677,923
Increase/(Decrease)	$60,303,384

Respectfully submitted,



BEN JACKSON
Administrative Law Judge

12/1/2016
Date

C:

Commissioner Anthony
Commissioner Murphy
Commissioner Hiett
Joseph Briley
Teryl Williams
Nicole King
William J. Bullard
Patrick D. Shore
Kimber L. Shoop
William L. Humes
David A. Kutik
John D. Rhea
Patrick M. Ahern
Judith L. Johnson
Natasha M. Scott
Dara M. Derryberry
Thomas P. Schroedter
Ronald E. Stakem
Jack G. Clark, Jr.
Deborah R. Thompson
Rick D. Chamberlain
Cheryl A. Vaught
Scot A. Conner
Jon W. Laasch
James A. Roth
Marc Edwards
Dominic D. Williams
Thad Culley
Jacquelyn L. Dill
S. Laurie Williams
Casey Roberts
Lee W. Paden
George Wright
Thomas A. Jernigan
Melodie Garneau
Douglas Holsted

Appendix A

Testimony Summaries

Michael P. Gorman - Mr. Gorman is a Managing Principal of Brubaker & Associates, Inc. ("BAI"). He filed responsive testimony on behalf of the Federal Executive Agencies ("FEA") in response to the application of Oklahoma Gas & Electric Company ("OG&E" or "Company"). Mr. Gorman provided his extensive work experience and educational background in Appendix A to his responsive testimony. He has testified in approximately 35 U.S. state and U.S. federal jurisdictions on utility rate-setting, regulatory policy, and integrated resource planning proceedings. Mr. Gorman has also filed testimony in three Provincial jurisdictions in Canada, as well as filing testimony before the National Energy Board in Canada. Mr. Gorman has been a consultant in the field of utility regulations and energy economics since 1983.

Mr. Gorman's responsive testimony in this proceeding outlined the Company's proposed class cost of service study, revenue spread, and rate design for Large Power and Light Time-of-Use ("LPL-TOU") Rate 35. Mr. Gorman finds that the Company's class cost of service and proposed revenue spread are generally reasonable. However, Mr. Gorman takes issue with the Company's proposed rate design for the LPL-TOU (Rate 35) Service Level ("SL") 1 rate.

Mr. Gorman believes the Company's proposed rate changes for LPL-TOU SL-1 are unreasonable and should be modified. Mr. Gorman disputed the Company's claimed cost of service pricing for the LPL-TOU rate because of inconsistency in demand billing data used to allocate demand costs. Mr. Gorman observed that the Company did not adjust demand billing units for delivery voltage losses in developing demand allocation factors. Failing to adjust metered demand billing units for loss factors has the effect of shifting costs to high delivery voltage customers from low delivery voltage customers. Mr. Gorman also noted a material discrepancy in the demand billing units used to produce demand allocators, and the proof of revenue for the LPL-TOU class. This discrepancy appears to have shifted costs to SL-1 from the other Service Level rate schedule. Because of this discrepancy in the development of accurate demand allocators within the LPL-TOU rate class, Mr. Gorman disputed the Company's proposed rate design based on cost of service principles.

Mr. Gorman recommends a structure for the Service Levels within LPL-TOU should conform to the current LPL-TOU rate structure which reflects differences in distribution cost and voltage delivery losses across all LPL-TOU Service Levels. More specifically, Mr. Gorman recommends a reduced demand rate for LPL-TOU SL-1 relative to SL-2 to reflect differences in distribution cost between SL-1 and SL-2, and for SL-1 and SL-2 to have the same energy rates, which is consistent with the existing LPL-TOU rate structure.

Mr. Gorman also offered rebuttal testimony responding to the Staff's proposed treatment of incentive compensation. Mr. Gorman took issue with the Staff's proposal to modify the Corporation Commission of Oklahoma's long-standing practice of not allowing long-term incentive compensation expense to be included in a ratemaking proceeding, and

awarding only 50% recovery of short-term incentive compensations. Mr. Gorman supports his outlines as being fair and reasonable for ratemaking purposes, and require investors to pay for incentive compensations when the incentive targets primarily benefit investors.

Brian C. Andrews - Mr. Andrews, a Consultant at Brubaker & Associates, Inc. ("BAI"), filed testimony on behalf of the Federal Executive Agencies ("FEA") in response to the application of Oklahoma Gas & Electric Company ("OG&E" or "Company") filed in the captioned case. Mr. Andrews testified as to his education and professional experience. He testified that he holds a Bachelor's Degree in Electrical Engineering from the University of Missouri-St. Louis/Washington University Joint Engineering Program, as well as a Master's Degree in Applied Economics from Georgia Southern University. He testified that he is a certified Engineer Intern in the State of Missouri and a member of the Society of Depreciation Professionals. Mr. Andrews testified that this is his first depreciation related testimony filed before the Corporation Commission of Oklahoma ("Commission"), but he has filed depreciation related testimony in both New Mexico and Indiana.

In his responsive testimony, Mr. Andrews addressed the issue of the depreciation rates and expense proposed by OG&E. He specifically addressed three issues:

- The average service lives of the transmission and distribution ("T&D") accounts with 2014 account balances greater than $50 million;
- The dismantlement expenses requested by OG&E for its steam and other production plants; and
- The retirement dates of four steam plants.

Mr. Andrews provides a bullet point summary of his conclusions and recommendations, which result in a reduction to OG&E's test year revenue requirement of $37.2 million.

Prior to his discussion of the issues in this proceeding, Mr. Andrews testified to book depreciation concepts. He testified that book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service and that this recovery should occur over the average service life of the investment or assets. He testified that in addition to capital recovery, depreciation rates also contain a provision for net salvage, which is the scrap value of the asset less its removal cost. Net salvage is also recovered over the useful life of the asset.

Mr. Andrews provided a definition of depreciation accounting from the Code of Federal Regulations, which effectively defines depreciation accounting as a mechanism to provide for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Mr. Andrews testified that OG&E's proposed depreciation rates were calculated using the straight line method, the average life group procedure and the remaining life technique. Under this method, procedure and technique of developing depreciation rates, the unrecovered cost of plant in service is adjusted for the cost of net salvage, and is recovered over the

remaining life of the asset or group of assets. At the end of the useful life, the asset is fully depreciated.

Mr. Andrews then provided testimony regarding the actuarial life analysis that is performed to evaluate historical asset retirement experience. He provided a description of actuarial analysis that is continued in the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices manual. The description states that actuarial analysis is the process of using statistics and probability to describe the retirement history of property and that it is a powerful analytical tool and considered the preferred approach.

Mr. Andrews testified that in this type of analysis, there are two major steps. The first step is to use available aged data from the company's continuing plant records to create an observed life table. The observed life table provides the percent surviving for each age interval of property. The second step is to match the actual survivor data from the observed life table to a standard set of mortality, or survivor curves. Typically, the observed life table data is matched to Iowa Curves. The fitting process is both a mathematical fitting process, which would minimize the Sum of Squared Differences ("SSD") between the actual data and the Iowa Curves, and a visual fitting process. Though the mathematically fitting process provides a curve that is theoretically possible, the visual matching process will allow the trained depreciation professional to use informed judgment in the determination of the best fitting survivor curve.

Mr. Andrews then explained survivor curves and the notation he uses to describe them. He states that a survivor curve is a visual representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the average service life of the group of property and the composite remaining life. In this case, as well as the majority of others throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of group property. There are four types of Iowa Curves: right-moded, left-moded, symmetrical-moded, and origin-moded. Each type describes where the greatest frequency of retirements occurs relative to the average service life. Additionally, he states that a survivor curve consists of an average service life and Iowa Curves type combination. When describing property with a 50-year average service life that has mortality characteristics of the R2 Iowa Curves, the survivor curve would simply be notated as "50-R2."

Mr. Andrews then begins his discussion of his recommendations for this proceeding. For the T&D accounts, Mr. Andrews has recommended that the T&D book depreciation rates should be reduced by increasing the average service lives associated with the property contained in Accounts 350.2, 353, 353.1, 355, 356, 362, 364, 365, 366, 367 and 369 such that the survivor curves produce a better statistical fit to OG&E's property retirement data relative to the survivor curves being proposed by Mr. Spanos. Regarding the level of dismantlement expense for the production assets, Mr. Andrews testified that OG&E should not be allowed to begin recovering terminal dismantlement costs for its production assets as it has not produced any studies supporting its proposed level of dismantlement expense. He goes on to testify that

OG&E does not have a mandate to dismantle its production plants to a Brownfield site as they are proposing. This is significant because some of the infrastructure in place at existing production sites could be utilized for the next generation of power plants. This would reduce both dismantlement expenses for the current generation of power plants and reduce the development costs of the next generation of power plants located at existing sites. Mr. Andrews recommends that the Commission should order OG&E to conduct a thorough dismantlement cost study of its production assets, as well as a study that will consider the value of these existing sites for the next generation power plants before allowing OG&E to recover terminal dismantlement cost of existing production assets.

Lastly, Mr. Andrews recommends that the retirement dates of the Seminole Units 1-3 and Horseshoe Lake 8 be increased to reflect the dates that have been used in OG&E's 2014 and 2015 Integrated Resource Plans ("IRP").

Mr. Andrews then provides a detailed discussion of each of his recommendations. His first detailed discussion is with regard to his recommended changes to the T&D depreciation rates. Mr. Andrews testifies that he conducted a depreciation study which is attached to his responsive testimony as Exhibit BCA-1. In his depreciation study, Mr. Andrews conducted an actuarial analysis on all T&D accounts with 2014 balances greater than $50 million. Based on Mr. Andrews' depreciation study, he is recommending increasing the average service lives of 11 of the 15 accounts studied. These increases result in a reduction to the 2014 depreciation expense of $15.9 million.

Mr. Andrews then provides additional detail on the process used in his depreciation study. He describes the process that began with a thorough review of the OG&E depreciation study and Mr. Spanos' workpapers. He then describes the actuarial analysis that he performed using an Excel based model. His depreciation model was utilized to determine the Iowa Curve and average service life that best fit the significant points of the observed life table created by Mr. Spanos. He then used a statistical and visual analysis to select an Iowa Curves and average service life that results in a better statistical fit (lower SSD) than the survivor curves being recommended by Mr. Spanos. He then testifies to the structure of his depreciation study filed as Exhibit BCA-1. Based on his depreciation study, Mr. Andrews is recommending adjustments to the average service lives for 11 T7D accounts, which result in the reduction of depreciation rates for these accounts. For each of the accounts to which Mr. Andrews is recommending a change, the survivor curve used to determine the depreciation rates mathematically and statistically fit OG&E's retirement history data better than those being recommended by Mr. Spanos. Mr. Andrews presents his Table 5 showing his recommended changes to the T&D depreciation rates. That table is reproduced below.

TABLE 5

Recommended Depreciation Rates

Account	OG&E	BCA	Delta
350.2	1.35%	1.26%	-0.09%
353	2.20%	1.95%	-0.25%
353.1	2.50%	2.27%	-0.23%
355	2.90%	2.57%	-0.33%
356	2.54%	2.06%	-0.48%
362	2.16%	1.80%	-0.36%
364	2.89%	2.33%	-0.56%
365	2.69%	2.45%	-0.24%
366	2.20%	1.75%	-0.45%
367	1.95%	1.80%	-0.15%
369	2.01%	1.75%	-0.26%

Source: Exhibit BCA-1

The next section of Mr. Andrews' responsive testimony discusses the production dismantlement costs. Before beginning his discussion of production dismantlement costs, Mr. Andrews provides testimony defining net salvage, which is simply the value received from the sale or reuse of retired property less the cost of removing the property. He then discusses the fact that the recovery of production dismantlement expense is a new concept being proposed by the Company and represents $18.3 million in the Company's proposed revenue requirement increase. Mr. Andrews then describes how OG&E is attempting to recover production dismantlement expense through the net salvage component of depreciation rates. Mr. Andrews then testifies that OG&E has not conducted a formal dismantlement cost study for any of its production plants and is relying on Mr. Spanos' experience to include a starting amount to include in depreciation rates. The level of expense that OG&E has proposed to recover for terminal dismantlement for its steam production plants is $40/kW and for its other production plants $10/kW. These costs are based on other utilities' studies reviewed by OG&E associated with dismantlement to a full Brownfield site.

Mr. Andrews then testifies that it is not reasonable to collect this uncertain level of terminal dismantlement expense. He points out the fact that in OG&E's current resource plans, it intends to reuse its existing production sites for the development of the next generation of power plants. He provided the examples of the Muskogee plant being retrofitted to run on natural gas and new combustion turbines and a solar plant are planned for the Mustang plant. Mr. Andrews then states there is likely an economic advantage to reusing these sites due to existing infrastructure and permits, so the assumption that the site will be removed from service is not reasonable. He suggests that OG&E has no current plans to dismantle these plants to a Brownfield site. Some of the existing infrastructure at these plants may be economically used for the next generation; therefore current ratepayers should not be required to pay for the cost of dismantling these facilities to a Brownfield site. It is

reasonable to assume that OG&E will continue to use its existing generation sites for the next generation of production assets.

Mr. Andrews presents his recommendation concerning the terminal dismantlement expenses for production plants. He recommends that no component for dismantlement costs be included in depreciation rates until OG&E conducts a formal dismantlement cost study that determines both an OG&E facility-specific dismantlement cost and considers the value of the existing infrastructure for the next generation of production assets. After such a study has been conducted and the proper level of dismantlement expense has been determined, it would be reasonable for OG&E to begin collecting such an expense. This recommendation results in a revenue requirement reduction of $18.3 million.

The last detailed section of Mr. Andrews' responsive testimony discusses the retirement dates of four of OG&E steam production facilities; Horseshoe Lake 8 and Seminole Units 1-3. Mr. Andrews testifies that the retirement dates used for the four facilities in the OG&E depreciation study are much sooner than what OG&E has used in its 2014 and 2015 IRPs. Mr. Andrews then presents a quote from OG&E witness Mr. Rowlett's direct testimony which states, "*In OG&E's recent integrated resource plan ("IRP") submittals, the Company has included estimated unit retirement dates. It is appropriate to reflect those retirement dates in the new depreciation study.*" Mr. Andrews then presents his Table 7 which compares the retirement of these plants used in the OG&E's depreciation study and the 2014 and 2015 IRPs. His Table 7 is reproduced below.

TABLE 7

Steam Production Probable Retirement Years

Plant	OG&E Depreciation Study	OG&E 2014-2015 IRPs	Delta
Horseshoe Lake 8	2029	2034	-5
Seminole 1	2030	2036	-6
Seminole 2	2030	2038	-8
Seminole 3	2030	2040	-10

Mr. Andrews then testifies to his recommendations concerning the retirement dates to be used for depreciation purposes for these four plants. Mr. Andrews recommends that the IRP retirement dates be used to determine the appropriate depreciation rates for these four plants. Mr. Rowlett has stated that it is appropriate to reflect the IRP retirement dates in the depreciation study. For the Horseshoe Lake 8 accounts, he recommends the composite remaining life be increased by five years. For the Seminole 1 accounts, he recommends the composite remaining life be increased by six years. For the Seminole 2 accounts, he recommends the composite remaining life be increased by eight years. For the Seminole 3 accounts, he recommends the composite remaining life be increased by 10 years.

Mr. Andrews then introduces his Exhibit BCA-6 which shows his recommended depreciation rates. He then discusses the impact of these depreciation rates on the test year depreciation expense. He introduces his Exhibit BCA-7 which shows the test year impact and presents his Table 8. His Table 8 shows the test year depreciation expense impact by depreciable group and is reproduced below.

TABLE 8

Test Year Depreciation Expense Impact
($ Millions)

Depreciable Group	Impact
Steam Production	$ (20.1)
Other Production	$ (0.5)
Transmission	$ (7.4)
Distribution	$ (9.2)
Total	$ (37.2)

Source: Exhibit BCA-7

Lastly, Mr. Andrews summarized his testimony into eight bullet points and concludes his testimony. His bullet point summary of his testimony is reproduced below.

1. OG&E has overstated its depreciation rates for several accounts. These rates produce an excessive amount of depreciation expense and overstate the test year revenue requirement.

2. The average service lives that Mr. Spanos is recommending for several T&D accounts should be increased. Statistical fitting methods indicate that survivor curves with longer average service lives fit OG&E's historic retirement data better than what is being proposed by Mr. Spanos.

3. The depreciation rates for Accounts 350.2, 353, 353.1, 355, 356, 362, 364, 365, 366, 367 and 369 should be decreased such that the average service life and Iowa Curves dispersion of the survivor curves for these property accounts produce a better statistical fit to the Company's retirement data.

4. OG&E should not be allowed to begin recovering terminal dismantlement costs for its production assets. OG&E has not produced any studies supporting its proposed level of dismantlement expense nor has it proven that the dismantlement expense it is proposing to recover is just and reasonable.

5. OG&E does not have a mandate to dismantle its production plants to a Brownfield site as they are proposing. Additionally, some of the infrastructure in place at these production sites could potentially be utilized for the next generation of power plants.

If existing infrastructure can be utilized for the next generation, both dismantlement expenses for the current generation of power plants would be reduced and development costs of the next generation would be reduced.

6. The Commission should order OG&E to conduct a thorough dismantlement cost study of its production assets, as well as a study that will consider the value of these existing sites for the next generation of power plants.

7. For depreciation purposes OG&E has reduced, relative to its 2014 and 2015 IRP, the retirement date of four of its steam production plants. These plants include Horseshoe Lake 8 and Seminole Units 1-3. These retirement dates should be increased such that the costs of these plants are recovered over the remaining lives that OG&E has been planning for over its last two IRP processes.

8. My recommendation to reduce the depreciation rates for the production, transmission, and distribution accounts reduces OG&E's test year depreciation expense by $37.2 million. This $37.2 million reduction consists of the reductions to depreciable groups shown in Table 1.

Christopher C. Walters - Mr. Walters, a Consultant at Brubaker & Associates, Inc. ("BAI"), filed testimony in response to the application of Oklahoma Gas & Electric Company ("OG&E" or "Company") filed in the captioned cause. Mr. Walters testified as to his education and professional experience. Mr. Walters testified he holds a degree in economics and finance from Southern Illinois University Edwardsville and a MBA from Lindenwood University. Mr. Walters also testificd that he earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. He testified that he has been employed by BAI for the last five years and is a Consultant. Mr. Walters testified that his past work experience has included, but is not limited to, return on equity, cost of capital, and financial integrity.

In his responsive testimony, Mr. Walters specifically addressed investor's current required return on common equity capital for OG&E. Mr. Walters also comments on:

- OG&E's requested capital structure;
- The indicated jurisdictional retail credit metrics produced using his recommended return on equity; and
- The direct testimony of Company witness Mr. Hevert.

To begin his analysis of an appropriate return on equity for OG&E, Mr. Walters first observed and described the current market outlook for regulated electric utilities offered by credit rating agencies such as Standard & Poor's ("S&P"), Fitch, and Moody's. Based on recent reports from these agencies cited in his testimony, Mr. Walters states that regulated utilities have experienced improved credit ratings in the recent past and the outlook has been labeled as "Stable" by these credit rating agencies. Mr. Walters also notes that these credit rating agencies have observed that utilities have strong access to capital at attractive prices, which has supported very large capital programs.

Mr. Walters then describes the performance of utility stocks over the last 12 years by comparing the Edison Electric Institute ("EEI") Index to that of the S&P 500. He testified that the data shows that the EEI Index has outperformed the market in downturns and trailed the market during recovery.

Mr. Walters concludes this section by testifying that credit rating agencies and the EEI consider the regulated utility industry to be stable and believe investors will continue to provide an abundance of capital to support utilities' large capital programs at moderate capital costs. All of this supports the continued belief that utility investments are generally regarded as safe-haven or low-risk investments, and the market embraces such low-risk investments. The demand for low-risk investments will provide funding for regulated utilities in general.

Mr. Walters next describes the market's assessment of the investment risk of OG&E. He testified that the market's assessment of OG&E's investment risk is described by credit rating analysts' reports. He notes that OG&E'S current corporate bond rating from S&P is A- with a Stable outlook. Mr. Walters cited a May 29, 2015, S&P report covering OG&E. That report notes that OG&E has a "strong competitive position" "very low industry risk." The report also notes that "[t]he Oklahoma economy remains healthier than those in other regions of the country and the state's unemployment rate remains well below the national average." Based on this assessment, Mr. Walters concludes that S&P views OG&E as stable, which is consistent with the utility industry in general.

Mr. Walters then describes OG&E's requested capital structure consisting of 53.31% common equity and 46.69% long-term debt. Mr. Walters testifies that OG&E's requested capital structure is not reasonable. To support this testimony, Mr. Walters cites his Exhibit CCW-2, which shows that the proxy group used to estimate the cost of equity for OG&E has an average common equity ratio of 49.6% compared to OG&E's requested 53.31%. Mr. Walters testifies that this average is more in line with what commissions across the country have determined to be reasonable and authorized for electric utilities over the last several years, and represents a more reasonable capital structure that would allow OG&E to access external capital at reasonable terms and prices, maintain its financial integrity, and lower costs to customers.

Mr. Walters further demonstrates the unreasonableness of OG&E's requested capital structure by providing Table 2 in his testimony, which shows that the average authorized common equity ratio for all electric utilities has fallen between 48% and 51% while averaging approximately 49.0% over the last 10 years. Similarly, vertically integrated electric utilities authorized common equity ratios have fallen between 48.4% and 51.2% with an average of 49.5% for the last 10 years.

Mr. Walters then testified that common equity is the most expensive form of capital available to the Company, mostly because of the fact that equity investors demand a premium over a bond return for bearing incremental risks associated with equity investments. The other reason equity is more expensive than debt is because of the fact that the equity return is taxable. He goes on to testify that by reducing the percent of capital that costs more than

three times the cost of debt, the cost savings would be passed on to customers through a lower total rate of return on rate base.

Concluding his assessment of OG&E's requested capital structure, Mr. Walters testified that he did not propose an explicit adjustment to the capital structure. He testified that he took the Company's requested capital structure into consideration in his recommended return on equity and his recommended range of an appropriate return on equity.

Mr. Walters proceeds to describe what is meant by a "utility's cost of common equity." He testified that a utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation. He also testified that, in general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Mr. Walters testified that these decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Mr. Walters testified that he used several models based on financial theory to estimate the cost of common equity for OG&E. He states that he relied on the following models: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). He testified that he has applied these models to a group of publicly traded utilities that have investment risks similar to OG&E.

Mr. Walters then details the process by which he used to select a risk-comparable proxy group. He testified that he relied on the same proxy group used by OG&E witness Mr. Robert Hevert, with the exception of Dominion Resources and Empire District Electric. Mr. Walters testified that he excluded these two companies from the proxy group for being parties to significant merger activity.

Mr. Walters testified that it is appropriate to exclude companies from the proxy group for being involved in merger and acquisition ("M&A") activity because M&A activity can distort the market factors used in DCF and risk premium studies. M&A activity can have impacts on stock prices, growth outlooks, and relative volatility in historical stock prices if the market was anticipating or expecting the M&A activity prior to it actually being announced. This distortion in the market data thus impacts the reliability of the DCF and risk premium estimates for a company involved in M&A. He then notes that Company witness Mr. Hevert also excludes companies from his proxy group for being involved in M&A activity.

Mr. Walters then compares the credit ratings and common equity ratios of the proxy group to those of OG&E in order to assess risk comparability. He testified that his proxy group has an average corporate credit rating from S&P of BBB+, which is one notch below OG&E's A- credit rating from S&P, and that his proxy group has an average corporate credit rating from Moody's of Baa1, which is three notches below the Moody's rating of A1 for OG&E. He also testified that his proxy group has an average common equity ratio of 46.6% (including short-term debt) from SNL Financial ("SNL") and 49.6% (excluding short-term debt) from The Value Line Investment Survey ("Value Line"). The Company is requesting a capital structure that has a common equity ratio that is approximately 3.7% (53.3% - 49.6% = 3.7%) higher than the comparable Value Line average common equity ratio for the proxy group.

Based on this comparison Mr. Walters concludes, and testifies, that the proxy group's risk profile is comparable within reason, if not conservative, for the risk profile of OG&E.

Mr. Walters then describes the DCF model stating that the DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. He testified that the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends. He states that he relied on a 13-week average stock price. He testified that an average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value. He also testified that a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

For the dividend component of the DCF model, Mr. Walters explains that he relied on the most recently paid quarterly dividend, as reported by *Value Line*. He testified that this dividend was then annualized and adjusted for next year's growth. Mr. Walters also testified that he used the average of analysts' growth rate estimates provided by Zacks, SNL, and Reuters. He explains that these growth rate projections are for three to five years out.

Mr. Walters testified that each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations. The average growth rate for Mr. Walters' proxy group is 5.53%.

Mr. Walters testified that the average and median results produced by the constant growth DCF model for his proxy group are 9.23% and 8.95%, respectively. Mr. Walters also testified that these results are a result of a growth rate that is higher than his estimate of a maximum long-term sustainable growth rate of 4.2%. For this reason, Mr. Walters testified

that he believes these results are overstated return estimates. Mr. Walters testified that a long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Mr. Walters later describes in his discussion of the multi-stage growth DCF analysis, academic and investment practitioner evidence accepts the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Hence, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and generally consistent with academic and economic practitioner accepted practices.

Mr. Walters testified that a reasonable proxy for the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Economic Indicators* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at approximately 4.2%. As such, the average growth rate over the next 10 years is around 4.2%, which he believes is a reasonable proxy of long-term sustainable growth.

Mr. Walters next describes a second form of the constant growth DCF model using a sustainable growth rate. Mr. Walters testified that a sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment. He states that the data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. The resulting average sustainable growth rate for his proxy group was 4.85%. Citing his Exhibit CCW-7, Mr. Walters states that the average and median result of his sustainable growth DCF analysis are 8.59% and 8.69%, respectively.

In regards to his sustainable growth DCF analysis, Mr. Walters testified that, while these growth rate projections are referred to as sustainable long-term growth rates, they are based on projections of earnings, dividends, and book value for the utilities three to five years out. Hence, these parameters may change over time, and may result in long-term growth rates being lower than that implied through the sustainable growth rate model.

Next, Mr. Walters explained that he also performed a non-constant growth DCF analysis, known as the multi-stage growth DCF analysis. He testified that his constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect the rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. To address this issue with the constant growth DCF model, he performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Mr. Walters proceeded to explain that the multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. He states that his multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period using

analysts' estimates of growth, which consists of the first five years; (2) a transition period, which consists of the next five years (years 6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity, which is the 4.2% GDP growth rate described earlier.

Mr. Walters testified that utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas. The U.S. Department of Energy, Energy Information Administration ("EIA") has observed that utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in his Exhibit CCW-8. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for utility sales growth, rate base growth, and earnings growth.

To assess the reasonableness of the 4.2% GDP growth rate, Mr. Walters compared it to five additional projections provided by various sources. He testified that the real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economist 5-year and 10-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks. Mr. Walters explained that he relied on the same annualized dividend and 13-week average stock price previously described.

The average and median results of his multi-stage DCF analysis, as shown on his Exhibit CCW-9, are 8.17% and 8.16%, respectively.

Mr. Walters concluded that his DCF studies indicate a return on equity of 9.0% based on a range of 8.70% to 9.25%. He testified that he believes certain constant growth DCF estimates using three- to five-year growth rate projections that are far too high to be rational estimates of long-term sustainable growth produce overstated DCF results. He states he is also concerned about the low-end DCF estimate as being reflective of capital cost when the rates determined in this case will be in effect. Therefore, he recommended a range of DCF returns of 8.70% to 9.25%, with an approximate midpoint estimate of 9.0% for OG&E based on his DCF studies.

Next, Mr. Walters described his bond yield plus risk premium model. He testified that this model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

Mr. Walters stated that he relied on two estimates of the equity risk premium. The first risk premium estimate is measured as the difference between the required return on utility common equity investments and U.S. Treasury bonds over the period 1986 through

2015. Mr. Walters testified that he relied on a rolling five-year average methodology to estimate a risk premium range. This methodology produced a risk premium in the range of 4.25% to 6.55%. The second risk premium estimate is measured as the difference between the required return on utility common equity investments and "A" rated utility bond yields over the same time period. Mr. Walters testified that he relied on the same rolling five-year average methodology to develop a risk premium range. This resulted in a risk premium over "A" rated utility bond yield of 2.88% to 5.43%.

Mr. Walters testified that he added a projected Treasury bond yield of 3.50% to his Treasury bond risk premium estimates of 4.25% and 6.55%. This produced an estimated common equity return in the range of 7.75% (3.50% + 4.25%) to 10.05% (3.50% + 6.55%). Mr. Walters stated that his risk premium estimates fall in the range of 7.75% to 10.05%.

Mr. Walters testified that he added a 13-week average "A" and "Baa" rated utility bond yield of 4.84% to his utility bond yield risk premium estimates of 2.88% to 5.43%. This produced a cost of equity in the range of 7.72% (4.84% + 2.88%) to 10.27% (4.84% + 5.43%).

In developing a recommended return on equity estimate based on his risk premium studies, Mr. Walters testified that he is recommending more weight to the high-end risk premium estimates than the low-end. He stated that this reflects the relatively low level of current interest rates and the above average credit spreads in "Baa" utility bond yield spreads over "A" rated utility bond yields and Treasury bond yields. For these reasons, he proposed to apply 75% weight to his high-end risk premium estimates and 25% to the low-end. Based on this methodology, the return estimate using his Treasury bond risk premium is 9.48%, and the return estimate using his utility bond risk premium is 9.63%. Based on these estimates, Mr. Walters recommended a risk premium return estimate of 9.6%.

Next, Mr. Walters describes the CAPM analysis. He testified that CAPM method is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. He then stated that the CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium as inputs.

Mr. Walters explains that he used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 3.50% for the risk-free rate and the average Value Line beta estimate of 0.77 for his proxy group for the beta estimate.

Mr. Walters testified that he derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average. The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. He estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation. This methodology produced a forward-looking market risk premium of 8.0%. The historical estimate of the market risk

premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook*. Over the period 1926 through 2014, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.1%, and the total return on long-term Treasury bonds was 6.10%. The indicated historical market risk premium is 6.0% (12.1% - 6.1% = 6.0%).

As shown in Exhibit CCW-16, based on his market risk premium estimates of 6.0% and 8.0%, a risk-free rate of 3.5%, and a beta of 0.77, the CAPM analysis produces a return of 8.11% to 9.64%.

Mr. Walters testified that, similar to his previous risk premium analysis, he placed 75% weight on his high-end CAPM return estimate, and 25% weight on his low-end. This produces a CAPM return estimate recommendation of 9.26%, rounded to 9.30%.

Mr. Walters then testified that, based on his analyses, he estimates OG&E's current market cost of equity to be 9.30%. He states that his recommended return on common equity of 9.30% is at the approximate midpoint of his estimated range of 9.00% to 9.60%. The high-end of his estimated range is based on his risk premium analysis. The low-end is based on his DCF studies. The CAPM return estimate falls within this recommended range.

Mr. Walters also testified that this range reflects current capital market costs, increased interest rate risk in the current market due to Federal Reserve policies and other factors such as relatively widening credit spreads, and represents fair compensation to OG&E's investors for the total investment risk of its regulated utility.

Mr. Walters concluded, and testified, that his recommended return on equity of 9.3% would support an investment grade bond rating for OG&E using S&P credit metrics to assess the financial integrity of OG&E. He then testified that he calculated each of S&P's financial ratios based on OG&E's cost of service for its retail jurisdictional operations. He noted that, while S&P would normally look at total consolidated OGE Energy's financial ratios in its credit review process, his investigation in this proceeding is not the same as S&P's. He stated that he is attempting to judge the reasonableness of his proposed cost of capital for rate-setting in OG&E's electric retail regulated utility operations in Oklahoma. Therefore, he is attempting to determine whether his proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and OG&E's financial integrity.

Mr. Walters shows the S&P financial metric calculations for OG&E at a 9.30% return are developed on his Exhibit CCW-17, pages 1-3. Mr. Walters noted that S&P currently rates OG&E's business risk as "Excellent" and financial risk as "Intermediate." The credit metrics produced, with this financial and business risk outlook by S&P, were used to assess the strength of the credit metrics based on OG&E's retail operations in Oklahoma.

Mr. Walters stated that OG&E's adjusted total debt ratio for retail cost of service is approximately 47.2%. This adjusted total debt ratio will support an investment grade bond rating. Based on an equity return of 9.30%, OG&E will be provided an opportunity to

produce a debt to EBITDA ratio of 2.7x, which is within S&P's "Intermediate" guideline range of 2.5x to 3.5x. OG&E's retail operations FFO to total debt coverage at a 9.30% equity return is 32%. The FFO to debt ratio projected for 2015 is within S&P's "Intermediate" range of 23% to 35%. These FFO/total debt ratios will support an investment grade bond rating. Mr. Walters testified that, based on this analysis at his recommended return on equity of 9.3%, OG&E's financial credit metrics are supportive of its investment grade utility bond rating.

Next, Mr. Walters discussed the reasonableness of Company witness Mr. Hevert's recommended return on equity and the analysis he relied on to support that recommended return on equity. Mr. Walters testified that Mr. Hevert's return on equity estimates are not reasonable and that Mr. Hevert's estimated return on equity is overstated and should be rejected. Mr. Walters then testified that Mr. Hevert's analyses produce excessive results for various reasons, including the following: (1) his constant growth DCF results are based on excessive, unsustainable growth rates; (2) his multi-stage DCF is based on an unrealistic GDP growth estimate and unsustainable payout ratio assumptions; (3) his CAPM is based on inflated market risk premiums; and (3) his Bond Yield Plus Risk Premium is based on inflated utility equity risk premiums.

In regards to Mr. Hevert's constant growth DCF analysis, Mr. Walters testified that Mr. Hevert's constant growth DCF studies generally support a mean return on equity of approximately 9.30% to 9.40%. Mr. Walters noted that Mr. Hevert's and his constant growth DCF return estimates produce reasonably consistent results. However, Mr. Hevert's DCF return estimates are overstated because they are based on an average growth rate of approximately 5.50% from all of his sources. Mr. Walters testified that this growth rate is a very optimistic future growth in comparison to long-term GDP growth of 4.2% as he previously described in regards to his own DCF studies. As such, Mr. Hevert's constant growth DCF return estimates should be considered very high estimates of the current market cost of equity.

Mr. Walters then testified that Mr. Hevert's multi-stage DCF analysis is flawed for at least two reasons. First, Mr. Hevert relied on a long-term GDP growth rate of 5.22%. Mr. Walters stated that this is not a reasonable estimate of long-term growth because Mr. Hevert's long-term GDP growth rate is considerably higher than the market GDP growth outlooks as reflected in the consensus analysts' projections. Second, Mr. Hevert modified analysts' three- to five-year dividend payout projections of 60.95% for his proxy group, and assumed that eventually they would converge to the historical industry average dividend payout ratio of 67.30%.

Mr. Walters testified that Mr. Hevert's 5.22% nominal GDP growth rate is not reflective of consensus market expectations and should be rejected. Mr. Walters noted that Mr. Hevert's 5.22% GDP growth rate outlook is inconsistent with the consensus of economists' independent projections of future long-term GDP growth of 4.2% that he previously described.

Mr. Walters then testified that there is simply no reason to expect the dividend payout ratio of the proxy group will increase toward the utility industry historical average. The utility industry average dividend payout ratio data used by Mr. Hevert shows that the payout ratio for the industry has been declining. There is no basis to assume, as Mr. Hevert does, that the payout ratio will start to change direction and increase through the transition stage of his DCF model.

Mr. Walters then proposed corrections to Mr. Hevert's multi-stage DCF analysis. Mr. Walters testified that revising the GDP growth rate of 5.22% to the consensus analysts' projection of 4.2% and coordinating the payout ratio assumption with the long-term earnings growth rate assumption reduces Mr. Hevert's multi-stage growth DCF return from 9.71% to 8.53% for his proxy group.

Mr. Walters then testified that by giving equal weight to Mr. Hevert's mean constant growth DCF estimates and his revision of Mr. Hevert's multi-stage DCF estimates, the return on equity falls in the range of 8.5% to 9.4%.

Next, Mr. Walters described the issues he has with Mr. Hevert's CAPM analysis. Mr. Walters testified that his major concern with Mr. Hevert's CAPM analysis is his inflated market risk premium estimates. Mr. Walters then testified that Mr. Hevert's DCF-derived market risk premium estimates are unreasonable. Mr. Hevert's DCF-derived market risk premiums are based on market returns of approximately 13.22% and 12.65%, which consist of growth rate components of approximately 11.06% and 10.37% and a market weighted expected dividend yield of approximately 2.16% and 2.28%, respectively.

As Mr. Walters previously testified, the DCF model requires a long-term sustainable growth rate. Mr. Hevert's sustainable market growth rates of approximately 11.06% and 10.37% are far too high to be a rational outlook for sustainable long-term market growth. These growth rates are more than two times the growth rate of the U.S. GDP long-term growth outlook of 4.2%. As a result of this unreasonable long-term market growth rate estimate, Mr. Hevert's market DCF returns are inflated and not reliable.

Based on this assessment of Mr. Hevert's analysis, Mr. Walters makes corrections to Mr. Hevert's CAPM using (1) Mr. Hevert's risk-free rates of 2.90% and 3.48%; (2) average published Bloomberg and *Value Line* beta estimates of 0.65 and 0.76, respectively; and (3) Mr. Walters' calculated high-end market risk premium of 8.0%. Mr. Walters then testified that this corrected analysis shows that Mr. Hevert's CAPM would be no higher than 9.6%.

Next, Mr. Walters described Mr. Hevert's bond yield plus risk premium analysis. He stated that Mr. Hevert constructs a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to interest rates. He estimates an average electric risk premium of 4.48% over the period January 1980 through October 15, 2015. Then he applies a regression formula to the current, near-term, and long-term projected 30-year Treasury bond yields of 2.90%, 3.48%, and 4.90% to produce electric risk premiums of 7.15%, 6.64%, and 5.68%, respectively. Thus, he calculates return on equity estimates of 10.05%, 10.12%, and 10.58%, respectively.

Mr. Walters testified that he takes issue with Mr. Hevert's risk premium analysis because Mr. Hevert's contention that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship among these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.

Mr. Walters then testified that changes in nominal interest rates are heavily influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates. Mr. Walters then testified that Mr. Hevert's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology that does not produce accurate or reliable risk premium estimates.

Mr. Walters also takes issue with Mr. Hevert's long-term projected Treasury bond yield of 4.90% because it is simply too high to be a reasonable projected Treasury yield. Mr. Walters stated that Mr. Hevert's projected 4.9% yield is approximately 210 basis points higher than the current Treasury bond yield of 2.81% and approximately 140 basis points higher than the projected Treasury yield of 3.50% that will cover the rate effective period as projected by the consensus economists. Mr. Hevert's long-term projected Treasury yield of 4.90% is well beyond the rate effective period, and as such, is not a reasonable interest rate to use in a risk premium study. For these reasons, Mr. Hevert's bond yield plus risk premium analysis should be disregarded.

Next, Mr. Walters testified that, by disregarding Mr. Hevert's simplistic and inaccurate notion of a continuing inverse relationship between interest rates and the risk premium will produce more realistic results. He stated that by adding his weighted average equity risk premium over Treasury bonds of 5.98% to Mr. Hevert's current (2.90%) and near-term (3.48%) projected Treasury yields will produce return on equity estimates of 8.88% and 9.46%, respectively. Therefore, if proper adjustments are made to Mr. Hevert's bond yield plus risk premium model, the fair return on equity for OG&E will be no higher than 9.46%.

In response to Mr. Hevert's assessment of current market conditions, Mr. Walters testified that in many instances Mr. Hevert's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with general corporate investments. A fair analysis of utility securities shows that the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is very low in today's marketplace. Mr. Walters cited his Exhibits CCW-13 and CCW-19 to support his conclusion that the market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities recognizing their low risk and stable characteristics.

Finally, Mr. Walters takes issue with Mr. Hevert's development and consideration of flotation costs. Mr. Walters stated that Mr. Hevert altered the DCF calculation in order to develop a dividend yield to reimburse investors the costs of issuing stock. Based on this calculation, Mr. Hevert states that he believes 12 basis points is a reasonable estimate of flotation costs. Mr. Walters testified that Mr. Hevert attempts to calculate an estimated flotation cost adder through a DCF study using his proxy group. This method does not measure OG&E's allocated share of actual flotation costs incurred by OG&E's parent company, OGE Energy Corp. Because Mr. Hevert has not shown these estimated flotation costs to be prudently incurred by OGE Energy Corp. and reasonably allocated to OG&E, the hypothetical flotation costs calculated by Mr. Hevert should not be taken into consideration.

Roger D. Walkingstick - My name is Roger Walkingstick doing business as RDSTICK Consulting, LLC. I have a bachelor's degree in electrical engineering from the University of Oklahoma. I also have a Masters of Business Administration from Oklahoma City University. I am a licensed professional engineer in the State of Oklahoma. I was an employee of OG&E for over 28 years, of which approximately 23 years was involved with rates, costing, rate administration, regulatory issues, and pricing functions for the Company. I retired from OG&E December 31, 2009, and have since worked with OG&E on a contract basis on various OG&E regulatory projects. I have testified before this Commission several times and this Commission has accepted my qualifications for the areas I cover in this testimony.

I have been retained on a contract basis by the Oklahoma Gas and Electric Company ("OG&E" or "Company") to address distributed generation ("DG") items in this Cause. I specifically rebut certain positions of TASC witness Garrett and Public Utility Division ("PUD") Staff witness Champion as addressed in their respective responsive testimonies.

In my rebuttal testimony, I testify that OG&E's DG customer count was 33 at the end of 2010 and is 246 as of June 30, 2015. Of the 246 customers mentioned, greater than 80 percent are residential customers and close to 90 percent of those customers are solar. Their annual kWh take from OG&E is a little less than an average residential customer (about 13,400 kWh a year for the average residential customer versus about 12,000 kWh a year for the average DG residential customer). However, a DG customer supplies between 4,000 kWh to 7,000 kWh a year from their own DG source. In addition, I testify that a DG customer causes higher transmission and distribution ("T&D") demands on the OG&E wires network than an average residential customer.

In my testimony, I disagree with Mr. Garrett that DG customers are providing a subsidy to non-DG customers. I discuss at length how a DG customer's bill is calculated. DG customers are currently compensated based on the energy charge under which they are billed. Because their energy charge includes items unrelated to production such as T&D wires costs and non-cost-based customer charge, DG customers are over compensated for their production to the detriment of other non-DG customers.

I further point out that Mr. Garrett fails to recognize that OG&E has provided a high level of compensation in its proposed rate design for DG customers due to the use of the 4CP allocator. The Company's proposed 4CP allocator lowers costs assigned to transmission and

provides greater incentive to production demand (the excess demand portion) for all kWhs generated in the on-peak window. The proposed rate design of OG&E reflects and rewards the DG generation provided in the on-peak window with an excess demand production credit through the on-peak energy charge. In the Company's rate design proposal, the transmission portion of the T&D demand charge is reduced by the recognition of lower assigned transmission costs due to 4CP allocator. This lower T&D demand assignment is lost to DG customers if they are included in either the residential class or commercial classes of service.

In addition, all current DG customers have the option to enroll in the Qualified Facility ("QF-1") tariff or if approved the proposed Renewable Power Purchase Option ("RPPO") tariff. The Company, under either of these tariffs, will purchase all generation.

I acknowledge that solar DG customers provide some offset to generation (production) across the summer peak hours. However, solar production declines at the start of the SmartHours on-peak window, and it is practically nonexistent by the end of that window. Solar production also drops substantially when a cloud blocks the sun's output to the DG customer's solar arrays. Additionally, solar production is not load following. If solar is available when the load is present, the result is good. However, solar generation is greatly diminished or nearly unavailable for a significant portion of the time when summer load is greatest.

Unlike a DG customer acting as a mini-generator, the Company must address or take into account the following issues: dispatchability, load following services, reliability, ancillary services and our inherent obligation to serve. And those costs are allocated to all customers in the class. Mr. Garrett recommends leaving the DG customers in their current classes by saying, "within the classes they belong, and not segregating and punishing them with draconian rate designs..." I must admit that both I and the Company are confused that Mr. Garrett is now recommending that DG customers be placed back into the classes from which they were removed, an apparent contradiction to the checklist he supported in PUD Cause No. 201500274.

I address and refute PUD witness Champion's concern that demands for DG customers may be higher than what OG&E calculated (estimated) which would lead to over collection of revenue from these customers. I explained that the demand charges for these DG customers are actual demands taken from these DG customers' meters.

In Ms. Champion's responsive testimony, she suggests that DG resources be evaluated in a manner similar to the Company's other demand programs. I do not agree with this premise. Demand reduction is only a small portion of what the DG tariffs are trying to accomplish. As stated when I addressed Mr. Garrett's concerns, DG customers have received a subsidy that allows them to avoid certain costs they cause to incur on the OG&E T&D system. They shift those costs onto other customers to pay. DG customers use the wires system of the utility as a delivery system but fail to pay for that use.

OG&E has proposed the RPPO purchase rider in this Cause as well as a R-TOU-kW DG tariff and the COM-TOU-kW DG tariff. These tariffs will correct the rate inequity that

has allowed DG customers' to avoid costs and reap benefits that they do not deserve. The tariffs are cost based, fair and comply with intent of SB 1456. They recognize that cost causers should pay and the proposed DG tariffs are designed with that objective in mind.

Scott Forbes - My name is Scott Forbes. I am employed by OGE Energy as the Chief Accounting Officer and Controller. My rebuttal testimony addresses the recovery of certain affiliate allocations and explains the Company's recorded Gain on Sale of Assets and the requested amortization period.

Administrative services such as auditing, accounting, finance, treasury, human resources, risk management, information technology, and supply chain services are integral to the operations of a publicly traded company, such as OG&E. OGE Energy Corp. ("OGE Energy") was formed in August 1995, and has provided those administrative services to its majority owned subsidiaries, OG&E and Enogex, since that time. OGE Energy, like the vast majority of other utility holding companies, provides administrative services, in order to reduce the cost of having redundant administrative costs when a company has multiple subsidiaries. OG&E customers have benefitted from the sharing of fixed administrative costs with Enogex since 1986, when it acquired Enogex. In 2013 Enogex combined with CenterPoint Energy's mid-stream company to form Enable Midstream Partners LP ("Enable"). Enable is now a publicly held company and during the test year canceled a number of the services previously provided by OGE Energy. During the six-month post test-year period, Enable canceled a number of the remaining services in August 2015 and December 2015.

In the current case, OG&E seeks to recover the cost of necessary administrative costs, absent the credit that Enogex/Enable has provided. It would be inappropriate to deny OG&E recovery of necessary administrative costs, as Mr. Garrett and Mr. Wielgus propose, simply because OG&E was able to benefit customers for the last 30 years by offsetting a portion of fixed administrative costs, but is unable to continue to do so.

Finally, in December 2015, OG&E entered into a transaction that incurred a gain on behalf of its customers of $962,500. The gain resulted from the sale in December 2015, and subsequent repurchase of a rotor in March 2016. The rotor will be used in a future outage at the McClain power plant, and is expected to be in service through the expected retirement in 2046. As such, I believe the gain should be amortized to customers over 30 years, the remaining life of the McClain plant.

William H. Wai - My name is William H. Wai. I filed direct and rebuttal testimony in support of Oklahoma Gas & Electric Company's ("OG&E" or "the Company") application. I am the Manager of Pricing. In that capacity, I am responsible for retail electricity pricing, rate design and tariffs. I earned a Bachelor of Science in Economics from Guangdong Institute for Nationals in Guangdong, China. I have a Master of Business Administration from the University of Oklahoma awarded in 2000. I have worked in the area of valuating and pricing commercial transactions for more than 12 years. I am a Financial Risk Manager and an Energy Risk Professional both certified by the Global Association of Risk Professionals ("GARP"). I am also a member of Chartered Financial Analyst ("CFA") Oklahoma Society.

First, I summarize the Company's process of developing the rates proposed in this application. Second, I describe structural changes to certain schedules of the Company's existing tariffs, particularly the residential, general service, and public school rate classes. Third, I present comparisons between the current and proposed rates, and discuss customer impact associated with these changes and updates. Finally, I sponsor OG&E's Proof of Revenue (Schedules M-1 through M-5 as well as Schedule N) for the proposed rate design.

I testify that the Company develops the rate proposed in this filing in five major steps. First, OG&E develops *pro forma* year data - actual test year data (revenues and billing determinants) are collected. Second, the Company calculates *pro forma* year's revenue from current rates by applying the rates approved in the Company's previous rate case to the billing determinants contained within the *pro forma* year data. Third, the Company analyzes its Cost of Service Study ("COSS") along with other inputs that are used in the development of the COSS. Fourth, the Company designs rates to recover the appropriate revenue requirements by class resulting from revenue allocation based on the COSS outcome. Finally, OG&E calculates the proposed revenue for each rate class and shows that the sum of the revenue requested from each rate class, plus other listed revenue, equaling the total OG&E requested revenue.

I sponsor the Company's proposed tariffs in this application which include two general changes to the existing rate structures. The structural changes are the incorporation of a kW demand charge for non-demand non-time-variable tariffs, and changes to the season definitions for the Standard Residential (R-1) tariff so as to eliminate separate rates for the shoulder months. I introduce a kW demand charge to each of the existing OG&E non-time variable rates which do not currently include a demand component. The proposed Residential ("R-1"), General Service ("GS-1"), Oil and Gas Producers ("OGP-ND"), Municipal Water Pumping ("PM") and Public School-Non Demand ("PS-ND") will each have a kW demand charge part incorporated into their existing two-part tariffs. The existing rates that already have a kW demand charge will continue as a three-part rate; and their kW demand charges are updated to reflect the latest cost of service information.

In addition, I calculate an overall average impact for each of the Company's customer rate class and as well as perform a comprehensive customer impact study for various groups of every rate class. Some average overall impacts and outcomes of the comprehensive customer impact study are highlighted in my direct and rebuttal testimonies. The overall average impact to R-1 residential customer bills is a monthly bill increase of 7.3% or $8.05 per month per customer. The average billing impact to a GS customer is approximately 13.0%, or a $22.72 per month increase. The overall impact to the PS-Small Service Level 5 customers is an increase of 13.4%, about $61.51 per month on average. For the PS-Large Service Level 5 customers, the average monthly bill is increased by 12.4% or slightly more than $380.44. The overall impact to OGP, Service Level 5 customers is an increase of 3.0%, equating to an average monthly increase of $7.66. PM Service Level 5 customer's average billing will decrease by 0.2% or $0.78 per month. OG&E proposes that there be no change to price levels in SL 1-4 for PL and PL-TOU.

I conclude by discussing that Schedule M-4, the Proof of Revenues statement, shows that the proposed prices when applied to the test year *pro forma* billing determinants will produce the revenues requested by the Company as shown in its COSS and Schedule B-1.

In addition, I offer rebuttal testimony to address the issues raised by Attorney General ("AG") witness James Daniel and Federal Executive Agencies ("FEA") witness Michael Gorman in the areas of customer impact and rate design.

First, I disagree with AG witness Daniel's claim that the Company's average impact calculation is misleading and inconsistent. I point out that, besides being required to be calculated based on total bill in Oklahoma and Arkansas, the Company's average impact calculation is in fact transparent and the same across the Company's filings. I continue by demonstrating why AG witness Daniel's customer impact calculation in Exhibits JWD-7, JWD-8, and JWD-9 is misleading. Second, while I agree that AG Witness Daniel's proposed R-1 rate structure recognizes the three-part rate in concept, I disagree with witness Daniel's proposed R-1 rates because the proposal lacks the proof that it would support the AG's proposed revenue requirement.

I take issue with FEA Witness Gorman's claim that load characteristics between LPL-TOU SL-1 and SL-2 are not materially different. The discrepancy in pricing for capacity and energy as proposed in the respective rates are fully justified. I also address witness Gorman's presumed "problem" billing units by comparing the Company's billing determinants with the demand units used in COSS.

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

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

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

results, Mr. Hevert recommends that an ROE in the range of 10.25 percent to 10.75 percent represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Mr. Hevert's recommendation considers the proxy group analytical results as well as additional factors including: (1) the risks associated with environmental compliance plans; (2) OG&E's significant level of planned capital expenditures; (3) flotation costs; and (4) the effect of certain rate mechanisms on the Company's relative risk profile.

As to the Company's requested capital structure, which includes 53.31 percent common equity and 46.69 percent long-term debt, Mr. Hevert notes that the proposed equity ratio is within the range of ratios in place at comparable operating utility companies and therefore is reasonable.

Mr. Hevert's Rebuttal Testimony addresses the Responsive Testimonies of Mr. David J. Garrett on behalf of the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Staff"); Mr. J. Bertram Solomon on behalf of the Oklahoma Attorney General ("OAG"); Mr. Christopher C. Walters on behalf of the Federal Executive Agencies ("FEA"); and Mr. David C. Parcell on behalf of Oklahoma Industrial Energy Consumers ("OIEC") (the "Opposing ROE Witnesses") as their testimony relates the Company's Return on Equity ("ROE") and capital structure. Mr. Hevert's Rebuttal Testimony includes a set of updated analyses supporting his Cost of Equity recommendation; those analyses demonstrate that his recommended range of 10.25 percent to 10.75 percent remains reasonable and appropriate.

Mr. Hevert's Rebuttal Testimony explains that none of the arguments provided by the Opposing ROE Witnesses have caused him to change his recommendations regarding the Company's ROE and capital structure. The fact that the Opposing ROE Witnesses' recommendations are similar in measure does not mean that their analytical approaches are appropriate, or that their recommendations are reasonable. Regardless of the analytical approach taken, the Opposing ROE Witnesses' recommendations fall far below observable measures of reasonableness, such as the returns available to other utility companies. Mr. Hevert notes that the highest of the Opposing ROE Witnesses' recommendations, 9.30 percent, falls below 105 of the 108 returns authorized for vertically integrated electric utilities from January 2012 through February 2016.

Although there are specific reasons why their individual recommendations are unduly low, there also are factors that commonly reduce the Opposing ROE Witnesses' analytical results. For example, in applying their Discounted Cash Flow models the Opposing ROE Witnesses rely on growth rates that are inappropriately low, or that are constrained by what they may consider to be "sustainable" or "fundamental" levels of long-term growth. Similarly, the Opposing ROE Witnesses' Capital Asset Pricing Model analyses rely on inputs that are incompatible with long-term experience, or cannot be supported by expected market and economic conditions. Mr. Hevert's Rebuttal Testimony also explains that although the Opposing ROE Witnesses may point to the level of interest rates to support their ROE recommendations, they do not recognize that the two do not change on a one-to-one basis. Consequently, their recommendations are low in the context of prevailing interest rates; they are lower still considering expected increasing interest rates going forward.

As to the Company's requested capital structure, which includes 53.31 percent common equity and 46.69 percent long-term debt is reasonable. Certain of the Opposing ROE Witnesses suggest capital structures with even higher levels of debt, arguing that a debt ratio as high as 60.00 percent is "optimal". Mr. Hevert demonstrates that the analyses underlying those conclusions are deeply flawed, and that reducing the equity ratio below the Company's recommendation would have the counter-productive effect of increasing its risk and, therefore, it's overall Cost of Capital.

Patricia Ruden – My name is Patricia Ruden. I am the Director of Total Rewards at OGE Energy Corp., which is the parent company of the wholly owned subsidiary Oklahoma Gas and Electric Company. I filed direct testimony as to the reasonableness of OG&E's compensation plans and to support the recovery of the costs for our compensation plans as a necessary cost of doing business.

I explain that OG&E focuses on the development of compensation programs that are performance-based and align with the business strategy. OG&E incorporates the establishment of market-based levels of compensation that enable the Company to compete for, attract and retain experienced, motivated and diverse members with skill sets necessary to execute the business strategy. Attracting and retaining quality employees depends to a large extent on the total compensation package available to those employees. In OG&E's case, the technical nature of our work, the competition for many of our critical jobs and an aging workforce make it particularly important that we correctly create "total rewards" packages that will attract and retain members.

OG&E employees are compensated with a base salary, short-term incentive compensation ("STI"), and in the case of vice presidents and directors, long-term incentive compensation ("LTI"). These components of pay serve different purposes and all are needed to attract and retain our members, base pay is the largest component of pay. STI and LTI are a smaller portion of the total pay package and are pay is at risk and not paid unless it is earned. The STI plan has a one year performance cycle. All full-time members are eligible to participate. Each eligible employee has a target percentage assigned based on their salary grade level. STI payout is based on the level of achievement met for each performance metric. A member hired during the plan year is eligible to receive a prorated award based on the number of full months of participation.

OG&E also has a stock incentive plan that includes long-term incentive ("LTI") grants of Performance Units to a select group of participants including officers, directors, and select senior managers. These grants are intended to drive business decision that results in long-term company performance and promotes shareholder value. LTI is at risk compensation, meaning that it is not paid if it is not earned. As these awards are earned at the end of a three-year performance cycle, they promote a longer-term view of the business. Awards consist of two performance plan components, Relative Total Shareholder Return ("TSR") and Earnings Per Share ("EPS"). TSR and EPS are consistently the most utilized metrics in long-term incentive compensation for companies, regardless of the industry. Both TSR and EPS are indicators of how strong we are as a Company as compared to other utility peers. Customers benefit if these indicators are strong because OG&E will attract more investors and have

access to cheaper capital, lowering the cost of providing service to customers. Conversely, if these indicators are weak as compared to the market, customer costs go up.

In order to assure that the Company remains competitive and fiscally responsible in our compensation programs, OG&E performs an extensive annual market analysis to assess the competitive positioning of its jobs in comparison to external competitive markets. Market studies indicate that Competitive Companies in the utility sector and general market utilize long and short term incentive pay as a part of their total compensation. If the Company did not offer incentive pay, it would need to increase base pay in order to remain competitive.

Incentive pay places a portion of employee pay at risk, making it dependent on their performance and the Company's performance. If the Company does pay out incentives, this means that the Company has benefited customers with greater efficiency, lower costs, improved reliability, safety, compliance and healthier financial performance, which translates to lower costs for customers.

Based on 25 years of experience in a variety of organizations, I can tell this Commission with confidence that attracting and retaining quality employees depends to a large extent on the total compensation package available to those employees, OG&E's approach allows us to hire the personnel necessary to provide the service our customers expect and deserve at the most reasonable cost.

John J. Spanos - John J. Spanos with the firm of Gannett Fleming Valuation and Rate Consultants, LLC, testified on behalf of Oklahoma Gas and Electric Company ("OG&E" or "Company").

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

In his testimony, Mr. Spanos addresses the need to include a dismantlement component for generating facilities as well as depreciation rates for new asset classes.

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

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

depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Mr. Spanos further testified that field reviews are important in the conduct of a study and his most recent field review for OG&E took place during November 2014 to observe representative portions of the plant. According to Mr. Spanos, field reviews are conducted to become familiar with Company operations and to obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Mr. Spanos testified that the depreciation study reflected future rates for LED lighting in Account 373, Street Lighting and Signal Systems as well as new facilities at Mustang, Sooner and Muskogee.

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

In rebuttal testimony Mr. Spanos stated he was responding to the direct testimonies filed by Public Utility Division ("PUD") witness David Garrett; Oklahoma Industrial Energy Consumers ("OIEC") witness Jacob Pous; and Federal Executive Agencies ("FEA") witness Brian Andrews on depreciation related issues.

The first part of Mr. Spanos' rebuttal testimony presents a general discussion of the depreciation study process. He discusses both the objective of depreciation in allocating the full costs of the Company's assets (original cost less net salvage) over their service lives, and the process and judgments involved in estimating service lives and net salvage. Mr. Spanos explains in detail, the depreciation study and the evidence supporting it are consistent with depreciation studies conducted across the country and the study is consistent with accepted practices in the industry.

Each witness's proposal regarding production net salvage amounts do not meet the objectives of depreciation of allocating costs over the service lives of the plant, and instead potentially defer costs to future customers who will not receive any service from the plant. OIEC, FEA and PUD's proposals for some mass property service lives do not correctly interpret the historical data and do not utilize the proper judgment in estimating service lives, and as a result forecast service lives for the Company's assets that are far too long for the types of property studied. Both OIEC and PUD incorrectly estimate longer life spans for wind assets based on only one force of retirement. OIEC's net salvage analyses similarly results in net salvage estimates that will recover far less than the full cost of the Company's assets for many accounts.

After the general section, Mr. Spanos addresses in more detail the specific adjustments and criticisms to the depreciation study that each witness proposes. These include:

- Terminal net salvage for production plant accounts. In order to recover the full cost (original cost less net salvage) of the Company's assets, the net salvage estimates for production plant accounts should include a component for terminal net salvage, or the decommissioning of the facilities. While all parties agree that it would be preferable to have a site specific decommissioning study, such a study is not available at this time. However, this should not mean that nothing is estimated for terminal net salvage, as OIEC and FEA have proposed. I have recommended estimates that are consistent with others used in the industry, and as I will explain, are also consistent with estimates from other cases in which OIEC's witness has been involved. Given that there will be costs incurred upon the retirement of the Company's facilities, terminal net salvage costs should be included in depreciation, and the depreciation study incorporates reasonable estimates of these costs.

- Wind production plant life spans. The life spans for wind production plant recommended in my depreciation study are 25 years, which is the same estimate currently used for wind for OG&E. This estimate is consistent with those of others in the industry. PUD and OIEC have recommended longer 30 year life spans. However, as I will explain, their estimates are based on how long the plants could last, and do not properly incorporate other factors that could result in the retirement of wind facilities at an earlier age.

- Mass property life analysis. PUD, FEA and OIEC have recommended different service life estimates for certain mass property accounts. The process of estimating service lives for mass property (e.g. transmission and distribution plant accounts) incorporates statistical life analysis but must also incorporate proper judgment. Authoritative depreciation sources are clear that judgment must be employed so that the resulting service lives are reflective of the property being studied.

PUD and FEA have estimated the changes to the largest number of accounts. PUD's estimates are inappropriately based solely on mathematical curve matching. FEA also appears to incorporate nothing more than mathematical curve matching into their recommendations. As a result, both parties' estimates are unreasonable and unrealistic for the property studied. For example, Mr. Garrett has estimated that a portion of the Company's overhead transmission poles account will remain in service for more than 150 years. Given that Mr. Garrett's process has resulted in what amounts to very unreasonable estimates, his recommendations should not be adopted by the Commission.

OIEC has only recommended adjustments to the service life estimates I have made for four accounts. As I will explain, OIEC's estimates are not as reasonable forecasts of future service life characteristics as my estimates.

- Mass property and interim net salvage. PUD and FEA have not recommended any changes to the Company's net salvage estimates for either mass property or interim net salvage for production plant accounts. OIEC has recommended adjustments to the net salvage estimates for four transmission plant accounts, one general plant account, and for the interim net

salvage estimates for steam production plant accounts. As I will explain, in making his estimates, Mr. Pous chooses to ignore the Company's actual experience and propose estimates that deviate significantly from the historical data. Strangely, Mr. Pous is also critical of my study for doing the type of analyses he had argued was necessary in the Company's previous study. Mr. Pous' recommendations are for net salvage estimates that are far below the Company's actual experience and as a result his analysis produces estimates that are far less negative than appropriate.

- Holding Company depreciation and amortization of software for electric plant. Mr. Pous recommends changes to holding company depreciation. Not only has there not been a study performed for these assets, which would be necessary to change depreciation rates, but Mr. Pous' recommendations are not based on the actual specifics of holding company assets. Instead, he has simply made speculative changes to service lives. Similarly, his recommendation for electric plant software is not consistent with the facts.

Jarod Cassada - My name is Jarod Cassada. I am employed by Oklahoma Gas and Electric Company as Supervisor, Vegetation Management. My direct and rebuttal testimonies address the Company's request for an increase in the *pro forma* expense due to system expansion, contractor inflation, changes in the regulatory environment, and the need to maintain a four year cycle.

In my direct testimony, I state that vegetation management is the integration of various control methods for the purpose of managing "space" around the conductors to prevent interruptions, while adhering to several standards and regulations, these regulations come mainly from the National Electric Safety Code ("NESC"),[18] NERC,[19] American National Standards Institute ("ANSI"),[20] and the Commission.[21]

My testimony focuses on two primary areas: Transmission and Distribution. Since the last rate case, OG&E has undergone significant increases in their transmission and distribution infrastructure. The testimony and request for those two areas are summarized as follows:

Transmission: At the end of 2010, OG&E had 4,487 miles of transmission lines, including 958 miles of 345-500kV line. OG&E currently has 5,152 miles of transmission lines, including 1533 miles of 345-500kV line. This constitutes a 15% growth in the overall transmission system, but 60% increase in transmission lines regulated under NERC FAC-003-3 which includes OG&E's 345 kV and greater lines. Since 2010, the increase in line miles and associated transmission infrastructure has contributed to a need for increased spending of approximately $1.69 million, resulting in an approximately $4.5 million total transmission request in this case.

Distribution: The overhead distribution system has expanded by approximately 11%. OG&E currently conducts vegetation management activities on approximately 18,587 miles of

[18] NESC 218A1
[19] Reliability Standard FAC-003-2
[20] ANSI A300 (part 7), ANSI Z133-2012
[21] OAC 165:35-25-15

Oklahoma right of way. Maintaining the distribution system on a four year cycle, per OAC 165:35-25-15, provides excellent longterm cost management as well as ensuring a low frequency of outages and faster recovery from outages or system damage. Current base rates are insufficient to maintain an end-to-end four year cycle. OG&E was able to achieve an end-to-end four year cycle through the system hardening rider which expired a few years ago. I also testify about non-cycle work as a factor impacting distribution cycle work and that customer requests are considered non-cycle work because they are variable costs that can cause delays to cycle work. Since 2010, costs associated with non-cycle work have increased from $1.2 million to $2.4 million in 2014. The Company requests approximately $25.8 million/year for Distribution Cycle and Non-Cycle. The request allocates approximately $23.4 million/year for Cycle, approximately $2.1 million/year for non-cycle, and $357,877 for distribution substations. This increase over the $21.5 million average annual spend is reflective of increased contracting costs, increased line miles, increased variable costs associated with non-cycle work, and an increased number of trees on the system.

In my testimony I state there are several factors that impact distribution cycle work. During any given year, the Company can experience unanticipated natural events, contractor availability, cost issues, and increased customer requests. These issues adversely impact scheduled cycle maintenance which affects system reliability and can result in increased cycle costs.

Further, I testify that OG&E uses contractors to complete 100% of its transmission and distribution line clearance work. That OG&E is able to achieve the best price possible with the greatest flexibility using skilled contract labor, however, over the last five years contractor costs have increased by approximately 20%. Additionally, OG&E has experienced uncertainty with the availability of its vegetation contractors, which are a highly specialized workforce, in high demand by all regional utilities. Contractors may decide to pay contract penalties to seek work that is more profitable, thereby putting some OG&E cycle work at risk of being uncompleted as planned.

In conclusion, OG&E is requesting approximately $30 million total company vegetation management expense level. As discussed above, this includes $23.4 million in distribution cycle work, $2.1 million in distribution non-cycle work, $360,000 in distribution substation work and $4.5 million in transmission work

In addition to direct testimony, I also filed rebuttal testimony in this Cause. My rebuttal begins by rebutting the six recommendations of Attorney General ("AG") witness Mara. In addition to rebutting his recommendations, I also address inaccuracies in Mr. Mara's analysis of my direct testimony and corresponding work papers.

I also address responsive testimony from OIEC and OER witness Garrett, who recommends no increase to transmission spending. This ignores the fact that the majority of the new transmission lines built has not required vegetation management since the last rate case because the right-of-way was cleared during construction and the first follow-up application of herbicide post-construction was capitalized as part of the project. Beginning in 2016, these new lines will now need to be maintained, contributing significantly to the requested increase.

My rebuttal testimony also addresses the recommendation of Staff witness Thompson, who contends that a forward looking 4-year model provides a budgeted number that cannot be relied on with any certainty and that the amount collected in calendar year 2015 is the lowest observed since 2009. This statement ignores the fact that years prior to 2015 included the System Hardening rider costs for vegetation management. These costs ended in 2014. When excluding System Hardening costs from prior years, the Company actually spent more in 2015 than any other year since 2009.

The requested adjustment in the *pro forma* expense for vegetation management will allow OG&E to manage the system in the manner our customers have come to expect. It has been thoughtfully designed to address system expansion, contractor inflation, and the maintenance requirements set forth by this Commission and other regulatory bodies.

Gwin Cash - My name is Gwin Cash. I am employed by Oklahoma Gas and Electric ("OG&E" or "Company") as the Rate Administration Manager. My responsibilities include maintaining OG&E's tariffs on file with the regulatory commissions and ensuring consistent application of these tariffs in the manner in which they are intended. Additional duties include, but are not limited to, computing rider factors and monthly retail revenue reporting. Prior to joining OG&E's regulatory department, I worked as a Senior Business Analyst for one year in OG&E's Sales and Customer Support department and as a Workforce Analyst for seven years in OG&E's Customer Service department. I received a Bachelor of Science in Applied Mathematics with a Specialization in Computing from the University of California, Los Angeles in 1999.

In my direct testimony, I sponsor the *pro forma* revenue and sales adjustments to the Company's Schedule H of its Minimum Filing Requirements ("MFRs"). I will also explain the revisions to OG&E's Terms and Conditions ("T&C") and the proposed changes to OG&E's riders in the Company's tariffs.

I state that the Company has thirteen *pro forma* revenue adjustments to Schedule H. The total amount of *pro forma* adjustments the Company offers is a decrease of ($740,056,483). Adjustment 1 for "Unbilled Revenue and Over/Under Recovery Amounts" is an increase of $71,079,308. Adjustment 2 for "Special Contracts" is a decrease of ($1,691,615). Adjustment 3 for "Day-Ahead Pricing ("DAP")" is a decrease of ($1,102,478). Adjustment 4 for Year End Customers is an increase of $12,511,435. Adjustment 5 for "Manual Postings" is a decrease of ($799,027). Adjustment 6 for "Removal of Rider Revenue" is a decrease of ($145,531,351). Adjustment 7 for "Rider Revenue Rolling into Base Rates or the Fuel Cost Adjustment rider ("FAC")" is an increase of $83,043,903. Adjustment 8 for "Time-of-Use Best Bill Provision" is an increase of $2,644. Adjustment 9 for "Renewable Energy Certificates" is a decrease of ($3,676,668). Adjustment 10 for "Demand Program Rider Savings" is a decrease of ($2,145,908). Adjustment 11 for "Removal of FAC revenue" is a decrease of ($753,683,704). Adjustment 12 for "Weather Normalization" is an increase of $6,366,505. Adjustment 13 for "Municiapl [*sic*] Free Service, LIAP, and Senior Citizen Discount Surcharges" is a decrease of ($4,429,526). I then presented the total amount of *pro forma* adjustments to Schedule H in the amounts of a total decrease of ($740,056,483).

I offer six modifications to the Terms and Conditions. First, is the addition of a Rate Index for all of the fees, charges, and T&C. The second is changing the Standard Meter type from mechanical registers to digital registers resulting from the completion of OG&E's SmartGrid deployment in 2013. Third, is to remove the meter testing plan suspension language in the T&C which was authorized in Cause No. PUD 201100087. Fourth, the Company is proposing to decrease the Reconnect Fee to $26.00 from $35.00. Fifth, the Company is proposing to decrease the Service Initiation Fee to $22.50 from $25.00. Sixth, the Company is proposing to increase the Meter Test Fee to $95.00 from $50.00.

I state that the Company's goal is to both reduce and simplify its riders. In accordance with these goals, the Company is proposing to discontinue the following riders: RTSA, SmartGrid, STSA, System Hardening Program Rider, Security, and Crossroads. The Company is also recomputing the Military Base Tariff Credit ("MBTC") rider, and is resetting the Cogen Credit Rider ("CCR") to zero. Additionally, OG&E is proposing to credit all REC revenue through the FAC rider.

In my rebuttal testimony, I rebut Public Utility Division ("PUD") witness Kathy J. Champion and her responsive testimony regarding miscellaneous fees: service initiation fee, reconnect fee, and the meter test fee. PUD Witness Champion recommended the service initiation fee be set at $14 per transaction. I have calculated the current service initiation fee of $25 to be 11 percent above cost while OG&E's proposed fee of $22.50 is at cost and Ms. Champion's proposal of $14.00 is 38 percent below cost. PUD Witness Champion recommended the reconnect fee be set at $18.00 per transaction. I have calculated the current reconnection fee of $35.00 to be 35 percent above cost while OG&E's proposed fee of $26.00 is at cost and Ms. Champion's proposal of $18.00 is 31 percent below cost. PUD Witness Champion recommended the meter fee remain at $50.00 per transaction. I have calculated that OG&E's proposed fee of $95.00 is 2 percent below cost and Ms. Champion's proposal of $50.00 is 49 percent below cost.

Donald R. Rowlett

Direct Testimony

In my Direct Testimony, I provided my educational qualifications and employment history. I testified that I currently serve as Managing Director of Regulatory Affairs where I oversee the Company's economic regulatory activities with the Oklahoma Corporation Commission, the Arkansas Public Service Commission, and the Federal Energy Regulatory Commission.

The purpose of my testimony is to discuss the relief requested by the Company in this Cause and to explain why the Company is seeking a rate increase at this time. I testified that the Company is currently requesting an increase in rates of $92.5 million annually which constitutes a 4.9% increase over rates that previously set in 2012. The Company expect [sic] to place the new rates in effect no later than June 2016.

I testified that the Company is seeking an increase in rates for three primary reasons: 1) substantial growth in the Company's electric system since 2010 and the fact the vast majority of that investment is not currently being recovered in rates; 2) the termination of a wholesale generation contract for the benefit of retail customers, and 3) the fact that the Company's operating costs have increased since 2010 even though controllable operational costs, such as employee headcount, have remained virtually flat.

Regarding the growth in the Company's electric system, I testified that since its last rate case, the Company has invested over $2.2 billion in utility infrastructure, $1.6 billion of which is not being currently recovered from Oklahoma customers through rates or existing riders. The return required to support this new investment accounts for approximately $30.6 million of the Company's requested rate increase.

I testified in an effort to address increasing growth on the Company's system, several wholesale contracts were terminated to free-up generation to meet the needs of our retail customers. A result of those contract terminations involving approximately 300 MWs of power is that the capacity costs previously allocated to wholesale customers must now be allocated to retail customers. The total costs [sic] of moving existing generation from the wholesale to the retail jurisdiction is approximately $16.5 million.

I testified that even though the Company has worked hard to keep controllable operating costs down, operating costs, including depreciation and other expenses, have increased $90 million since 2010. Approximately $60.2 million of this increase is attributed to an increase in depreciation expense with increase in utility plant accounting for approximately $44.6 million to the depreciation expense. Additionally, the Company's proposal to begin recovering dismantlement costs make up approximately $15.6 million of the increase in depreciation expense.

I testified that all things considered, the average residential customer will see a net increase of only approximately $0.47 per month. When the $7.22 per month increase proposed in this Cause is combined with the reduction in fuel costs that will begin January 1, 2016, the total customer impact that results is minimal.

Discussion of Key Issues

1. Wholesale Contract Expiration

I testified that in 2007, the Company announced its goal to reach the year 2020 without adding incremental fossil-fueled electric generation thereby postponing the costs of new generation and allowing time to gain a clearer picture of the path forward in the environmental arena. Terminating the wholesale contracts provides over 300 MWs of generating capacity to retail customers without the addition of new generation. The generation resources made available through termination of the wholesale contracts includes coal, natural gas, and wind. The benefit of the wholesale contract terminations to retail customers is significant. If the Company was still serving its wholesale customers, it would need new incremental capacity in addition to existing capacity before next summer. Any new generation would be much more expensive than the $283 per kW cost of reallocating the wholesale portion of existing capacity.

For example, the cost of new combined cycle generation is estimated to be approximately $1,250 per kW.

2. Vegetation Management

I testified that vegetation management is a program to keep trees and other vegetation out of power lines with the goal of preventing outages during periods of high wind or ice. The Company has experienced significant growth in its transmission and distribution line miles. The increases since 2010 of 15% in transmission lines and 11% in distribution lines have impacted the level of spend required to maintain these lines on the system. The Company is requesting a $45.5 million increase from the average five-year spend for vegetation management. In addition, the Company is proposing a vegetation management tracker that will account for variances above or below the level recovered in base rates.

3. Depreciation

I testified that the Company is proposing a change in depreciation expense to account for the increased level of plant requested in this Cause as well as new depreciation rates. These changes increase total Company depreciation expense by approximately $29.6 million.

4. Production Tax Credit Rate Treatment

I testified that OG&E is requesting that the FAC be used to credit customers for the value of PTCs from the Centennial, OU Spirit, and Crossroads wind facilities. This treatment is consistent with the direction the Commission has been moving with respect to inclusion of costs related to the marginal costs of generating or purchasing energy into the fuel adjustment clause. An additional reason to move the PTCs into the FAC is that PTCs expire after ten years. The PTCs associated with the Centennial facility will expire in 2017. By moving the PTCs into the FAC, the level of PTCs can be adjusted monthly to reflect the actual level of credits being generated. Otherwise, the Company will have to file a rate case annually, starting in mid-2016 to account for these changes. This requested change does not affect the revenue requirement requested in this Cause.

5. Environmental Compliance Projects

I testified that the Company is requesting that the Commission: 1) include in rate base the low NOx burners and ACI environmental compliance projects that were completed and placed in service during the pro forma test year; 2) grant recovery of air quality control systems ("AQCS") consumable costs through the FAC; and 3) approve a regulatory asset for costs associated with low NOx burners and ACI environmental compliance projects that will be placed in service in 2016 and 2017. The Company has installed approximately $72 million in environmental projects at December 31, 2015, on both the Sooner and Muskogee plants. The revenue requirement for these EPA-mandated projects is approximately $11.4 million. The Company estimates the AQCS costs for the Oklahoma jurisdiction to be approximately $6.2 million annually in 2016 and 2017.

6. Community Solar Pilot

I testified that the Company seeks to explore new technologies and customer options and to facilitate this objective, the Company sought to test the impacts of solar on safety, maintenance, and reliability on its electric system. The Company's solar project is constructed at

its Mustang facility and is a 2,250 kW solar production facility constructed in two arrays. The Company seeks to include in rate base the approximately $7.5 million of capital costs associated with the project.

7. Return on Equity

I testified that Company Witness Hevert recommends an ROE range of 10.25% to 10.75%. The Company has chosen to request the lower ROE in that range and requests the Commission authorize an ROE of 10.25%. The Company believes that 10.25% is consistent with the average ROE granted for utilities being regulated by "above average" regulatory jurisdictions and "A" rated utilities such as OG&E. I further testified customers benefit from Oklahoma having a constructive rating in the financial community. The Company believes it is in the customers' interests to be an attractive investment and that by authorizing an ROE consistent with similarly rated utilities and the best regulatory jurisdictions, the Commission sends a clear message that investors will be treated fairly when compared to similar investment opportunities.

8. Customer Rates and Program Options

I testified that the Company is focused on improving customer experience and overall satisfaction by sending appropriate pricing signals and offering additional customer programs. The Company has made several improvements to assist customers in managing their electricity costs including implementation of a new online platform to assist mobile users, the rollout of digital meters, and customer education regarding pricing and billing options and the idea that electricity costs more on-peak than it does off-peak.

I further testified that the Company is proposing eliminating six of its twelve current riders. Five of these riders are no longer needed because the costs included in those riders are being incorporated into base rates. Also, elements of the Renewable Transmission System Addition rider are being distributed to other riders.

Rebuttal Testimony

In my rebuttal testimony, I first address the issue of the extension of the Southwest Power Pool Costs Tracker ("SPPCT"). PUD Staff witness Chaplin suggests that language be added to the tracker that would allow a broader review of new factors in the event any annual adjustment exceeds 50% as compared to the previous year. I suggest additional language to the proposed tariff, as more fully set forth in my written testimony, that the Company believes will help facilitate the PUD's review.

I next testify in response to OER witness James Dauphinais regarding his recommendation that the SPPCT be discontinued. In response to Mr. Dauphinais' contention that three prerequisites must be shown to justify the creation of a rider, I observe that no such requirement exists in either this Commission's rule or Oklahoma statutes. Notwithstanding this fact, I testify that I believe in the case of the SPPCT, those prerequisites exists in that since 2012, the fees collected through SPP Schedule 11 have increased annually in a dramatic fashion, the amounts are large enough to cause financial concern to the utility, and the costs are not in the

control of the Company as they are imposed by SPP. I conclude that because of the robust SPP review process regarding these third-party projects, customers are protected.

I next respond to the responsive testimony of AG witness Paul Wielgus regarding the transfer of 300 MWs of generating assets to retail customers that were formerly dedicated to wholesale customers. In response to Mr. Wielgus' concern that the Company has improperly transferred all the risks and costs associated with the generating units, I testify that Mr. Wielgus has failed to both quantify the risks and costs and demonstrate that the benefit to customers is outweighed. It is difficult to imagine in today's market that customers could obtain a diverse portfolio of generating capacity at a cost of $283/MW.

In response to testimony regarding the inclusion of AQCS, RECs, GPWRR, and PTCs in the FAC, I testify that: 1) this Commission has previously included AQCS expenses in the FAC in a previous case, Cause No. PUD 201100082 (Order No. 592623), and the costs are appropriately included in the FAC as they are variable and highly correlated to the amount of fuel consumed in the generation process; 2) PTCs are appropriate for inclusion in the FAC as those credits will begin to expire in the next few years and by moving PTCs to the FAC, the level of PTC credited to customers can be adjusted each month to reflect the actual level of credits generated; and 3) that I agree with PUD's position that the FAC is the proper place to consolidate all REC revenue.

In response to AG witness Farrar's and Daniel's opposition to the Company's request for a regulatory asset regarding additional environmental compliance investments, I state my belief that this circumstance meets the criteria set forth by Mr. Farrar to justify a regulatory asset in that the costs associated with the environmental projects are substantial, necessary, and not within the control of the Company. I disagree with the assertion that the costs of the environmental upgrades will be offset by future cost reductions and increased revenue and I observe that in the event a regulatory asset is denied as suggested by Mr. Farrar and Mr. Daniel, a rate case would be required yearly to recover the substantial costs related to the projects.

Regarding the Company's request for a Vegetation Management Rider, I respond to AG witness Mara's opposition to that rider based upon his assertion that vegetation management is a "core competency" for utilities and that the related costs and challenges are known. I testify that the purpose of the rider is to account for variances above and below the level recovered in base rates. Variability regarding vegetation management is caused by a number of factors including but not limited to weather, storms, and specific types of vegetation.

I testify in response to testimony by PUD witness Thompson, AG witness Farrar, and OIEC/OER witness Garrett regarding the Company's adjustment for ad valorem taxes. I disagree with those witnesses opposition to the adjustment based on their belief that historic changes in valuation are not indicative of future tax expense. I state the Company's position that taking into consideration a recent historic period and observing changes in valuations and millages provides a proper basis to estimate future tax expense.

Regarding the issue of incentive compensation, I address the testimony of AG and OIEC/OER witnesses that support the exclusion of Long-Term Incentive compensation and the

inclusion of only half of Short-Term incentive compensation in rates. I testify that these costs are prudent expenditures and part of the compensation structure of our employees and that the Company needs to be competitive in the marketplace and attractive to existing and potential employees.

I testify in support of the Company's proposal that costs associated with Smart Grid stranded assets and the Smart Grid Portal be amortized over a six-year period consistent with this Commission's Order No. 576595 in Cause No. 201000029. I observe that the position of OIEC/OER witness Garrett in support of a longer amortization period is not supported by any other party to this Cause.

Supplemental Testimony

Lastly, I respond to the Supplemental Testimony filed by OER witness Mr. Dauphinais regarding his concerns that very early cost estimates prepared by SPP vary form [sic] the final costs of four projects constructed by the Company. I observe that the early figures associated with these projects found by Mr. Dauphinais on the SPP website were placeholder figures using a "rule of thumb" based on dollars per mile for essentially a straight line between the expected endpoints. I also discuss that, ultimately, alternative routes are often required to address environmental, landowner, reliability, possible litigation, and timing concerns. I summarize the SPP review process for new transmission projects and note this review process is robust and multi-layered to ensure well-planned, economic projects that are allocated to members in a fair and reasonable manner.

David Smith - My name is David Smith. I am the Senior Costing Analyst for Oklahoma Gas and Electric Company. I have a bachelor's degree in economics from the University of Central Oklahoma. Prior to joining the Company, I worked as a public utility regulatory analyst for the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") from 2005 to 2010.

My direct testimony presents and supports OG&E's jurisdictional and class cost of service studies ("COSS") and the development of the jurisdictional and class allocations and related schedules. My COSS relied on the Company's historical, or embedded, statements of revenue, number of customers, energy sales, accounting reports, engineering records, customer billing records and load survey data. I followed traditional methodology by including fixed and variable costs and joint or common costs in the COSS. Joint or common costs are those costs that are shared by all customers because they are incurred to produce jointly beneficial products.

I made allocations to customer classes using a three-step process: functionalization, classification, and allocation. Typically, functions in a fully integrated electric utility are: Production and Purchased Power, Transmission, Distribution, Customer Service, and, Administrative and General ("A&G"). Functionalized costs are further separated into three classifications: demand-related costs, energy costs, and customer costs. After costs are functionalized and classified, they are allocated or directly assigned among jurisdictions (Oklahoma retail, Arkansas retail and FERC). OG&E's major customer classes are generally grouped as Residential, General Service, Power and Light, Large Power and Light, and Other.

OG&E is proposing a functional allocation change for both Generation Step-up Transformers ("GSUs") and generation radial ties. The Company proposes in this case to allocate these costs as generation assets using a production demand allocator as opposed to using a transmission demand allocator.

OG&E proposes to recover the environmental costs as demand-related and to use production demand allocator, which is the same as all other production plants.

There are three primary demand allocators used in OG&E's COSS that support how costs should be allocated for the three main functions: production demand; transmission demand; and distribution demand. Each of the three functional categories of production, transmission, and distribution have different cost drivers that require different allocation methods to most accurately match costs to the cost causers. For Production Demand, OG&E proposes to determine the excess component by using an average of the four summer coincident peaks ("4CP") instead of using only the jurisdictional loads at the time of the system peak ("1CP"). The Company classified transmission as demand and allocated its transmission costs to its retail and wholesale jurisdictions by using an average of twelve monthly coincident peak demands ("12-CP"). OG&E classifies distribution plant costs as either demand related or customer related depending on the FERC account. Demand-related distribution costs were allocated based on class non-coincident peak demands ("NCPs"), as opposed to CPs. The customer-related distribution plant costs and certain associated expenses are allocated to the customers who require such facilities by using the weighted customer methodology.

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

In contrast, the jurisdictional cost of service study identifies the embedded cost of service for the Oklahoma retail, Arkansas retail and FERC jurisdictions. This embedded cost of service study is based upon cost allocation principles, reflects all of the test year adjustments, and establishes the cost responsibility for the provision of electric service to each jurisdiction. The class cost of service study quantifies the embedded cost of service for the Oklahoma retail individual customer classes that make up the Oklahoma retail jurisdiction.

My rebuttal testimony supports the classification and allocation of the Company's distribution plant costs in the COSS. Attorney General witnesses James Daniel and Kevin Mara, and TASC witness Mark Garrett are recommending that OG&E disregard its zero-intercept study results and allocate all associated distribution costs using a demand only allocator. I recommend that the Commission accept OG&E's zero-intercept study as filed and allow OG&E until its next base rate case to either update the study or propose other alternative methodologies that meet accepted cost allocation theory.

I also rebut FEA witness Gorman's assertion that there is not a significant cost difference for both production and transmission service for LPL-TOU SL-1 and SL-2

customers. Using Schedule L-1, I confirm that there are significant differences between the two service levels for production and transmission demand costs.

Ahmad Faruqui - The purpose of my direct testimony is to evaluate and benchmark the proposal by Oklahoma Gas & Electric to introduce demand charges to its default residential rate. I review the principles of rate design, assess how these principles are being practiced in the US, and compare the OG&E proposal against these principles and industry practices.

Professor Bonbright propounded ten principles of rate design that are widely used as a foundation for designing rates. I have distilled these principles into five core principles: economic efficiency, equity, revenue stability, bill stability, and customer satisfaction. OG&E's rate proposal is consistent with Bonbright's principles of rate design.

The proposal effectively captures the underlying costs of the system, making it economically efficient and equitable. It is simple for customers to understand and will allow them to manage their bills effectively. Furthermore, it is consistent with how OG&E charges its larger commercial and industrial customers, and the introduction of the rate will create uniformity in rate design across all customer classes.

Additionally, OG&E's proposal falls generally in line with the structure and magnitudes of other three-part rates. As I explain in my testimony, the proposed rates are a significant improvement over the current default residential rate.

The current rate, which is largely volumetric in nature, does not reflect the cost structure of delivering electricity. It sends inefficient price signals while creating inequities among customer classes. On the other hand, the proposed rate is progressive and forward-looking. The Commission should approve the proposal because it satisfies the principles of efficiency and equity, as well as the principles of simplicity, public acceptability, and feasibility of application.

My rebuttal testimony rebuts several points made by Attorney General witness Jeff Daniels, PUD staff witness Kathy Champion, and TASC witness Mark E. Garrett on the rate design proposals that have been put forward by OG&E. Contrary to intervener assertions, three-part rates should be rolled out now because they satisfy Bonbright's principles of rate design and smart meters allow utilities to measure customers' real-time demand.

Effective three-part rates eliminate cross subsidies between different groups of customers in the near term and incentivize efficient shifts in customer behavior over the long term. Two-part rates are an antiquated relic of the analog age, unsuited to the requirements of the digital age.

I disagree with PUD witness Champion's point that a gradualist approach should be used here to implement OG&E's three-part rate. A gradualist approach is not needed here because OG&E's proposed demand charge is already low in comparison to demand charges in other jurisdictions and customers can opt-out of the rate if they do not like it.

I also disagree with PUD witness Champion's claim that pilots need to be conducted before demand charges are rolled out. The primary issue is not whether customers will respond to demand charges or not; rather, the primary issue is the accurate reflection of costs in rates. As I demonstrate in Exhibit 1, two-part rates can create cross-subsidies between customer classes. By matching a utility's cost structure with its rate structure, these cross-subsidies can be eliminated.

Additionally, TASC witness Garrett claims residential customers find demand charges unattractive or unacceptable. In Arizona Public Service Company's service area, some 120,000 customers, or 10 percent of the customer base, have opted into a three-part rate. This is quite an accomplishment given that most customers are known to stick with the default rate. To my knowledge, there is no evidence that customers find demand charges unattractive.

Bryan J. Scott - My name is Bryan J. Scott. I am the Director of Pricing and Load Analysis for Oklahoma Gas and Electric Company. I have a Bachelor of Science degree in Economics from the University of Tulsa. I have been involved with electricity pricing, costing, rate administration and regulatory issues, for both electric utilities and as a consultant for over 35 years. In March 2008, I joined OG&E. In this proceeding, I testify in two areas: pricing goals and revenue allocation. I address the goals of OG&E's pricing approach and the process the Company used to develop pricing. Second, I describe the revenue allocation proposed by OG&E.

OG&E's pricing approach is to offer meaningful choices to customers while also collecting enough revenue to cover the cost of providing electric service to customers. OG&E currently offers alternative pricing plans that provide customers with more choices than just a traditional plan. Ideally, OG&E would offer customers the option to choose from at least three plans: (i) a standard or default price plan, (ii) a price response plan, and (iii) a price security plan.

Standard Price Plan. The standard price plan will reflect OG&E's allocated embedded costs by cost classification, becoming the foundation for other price offerings. First, the energy or kWh charges should recover electricity supply costs such as fuel costs and recovery for production costs of electricity. Second, the monthly fee often referred to as a customer charge, should recover metering costs, local distribution facilities, and customer billing and care costs. Third, the demand or kW charges should recover "wires" charges, i.e. transmission and distribution system fixed costs. The result is a three-part price plan that accurately recovers the utility's costs to provide electric service.

Price Response focused plans. Price response plans, such as the Company's Variable Peak Pricing ("VPP") plan, recognize the differences in electricity supply costs by time period. Price response plans offer customers the opportunity to maximize the value they receive from electric service by either reducing their usage during higher cost periods or by shifting usage to lower cost periods. These plans offer the most value to customers who wish to adjust their use of electricity to obtain the lowest bill possible.

Price Security focused plans. Price security plans offer subscribers increased convenience or bill certainty and recognize the increased risks to the Company of doing so. Some customers place more value on bill certainty than on achieving the lowest bill possible. OG&E enhances overall customer satisfaction by offering these customers options that address their desire for convenience or price/bill certainty.

OG&E proposes to re-start its pre-pay billing option, known as Pay-As-You-Go ("PayGo"), and to offer SmartMeter Opt Out options. The PayGo plan offers customers the choice of not providing a security deposit when initiating service, but instead, using the deposit to pre-pay for service. When their prepaid amount is consumed, subscribers must deposit additional funds for their service or their service will be discontinued. PayGo participants may generally choose from any pricing plan available. OG&E is simply offering this bill payment option as a voluntary alternative.

In the category of price response, OG&E proposes to terminate the TOU Critical Peak ("TOU-CP") pilot plans. These plans were TOU pricing plans that incorporated a price overall provision, where OG&E could post a higher peak period price when system conditions warrant a higher price. While other price response plans such as the VPP and TOU plans have had significant increases in customer participation, the TOU-CP plans have experienced declining subscription.

The Company established separate classes for Distributed Generation ("DG") customers in its Cost of Service Study ("COSS") and identified the unit cost by function. The proposed R-TOU-kW and COM-TOU-kW tariff prices were updated based on the new COSS.

I also testify to the Company's goals of revenue allocation through its COSS. The COSS establishes the amount of revenues that should be collected from each customer group or class if each class were to pay its cost for receiving electric service. When the class revenue requirement matches the cost of service, the class' revenue requirement is considered to be at 100 percent relative rate of return ("RROR") or equalized rate of return ("ROR").

A primary concern in revenue allocation is to set each class' revenue requirement as close as possible to a target RROR of 100 percent. In other words, each customer group should pay the full cost for its electric service. However, external or unusual circumstances may also be considered in the allocation of revenues to each class. Consequently, when moving classes toward their allocated cost of service, the Company must also incorporate allowances for these circumstances in its pricing proposals. For example, the Public School Non-Demand ("PS-ND") class revenue requirement and the associated time differentiated tariffs ("PSND-TOU", "PSND-VPP"), as determined by the COSS, would have caused pricing for these groups to increase to a level above that of the equivalent General Service tariffs. The pricing for the PS-ND tariffs was set at the equivalent GS tariff level and the balance of the COSS revenue requirement was collected from the GS customer group. The Public School Demand ("PS-D") customer group, including PS-D-TOU, had a similar result in the COSS, in that the prices would exceed the prices for the equivalent PL tariffs. The pricing for the PS-D tariffs were set at the equivalent PL tariff level and the balance of the COSS revenue requirement was collected from the PL customer group.

Although OG&E has proposed the above-mentioned deviations from the full COSS approach, OG&E still supports the goal of moving each class to its full cost of service. Without cost based prices, customers will be led to make poor choices regarding long-term investments regarding electricity. While, OG&E's proposal in this Cause is a step in the right direction it does not yet eliminate all cross-class subsidies.

In addition to my direct testimony, I also filed rebuttal testimony to respond to issues raised regarding pricing by Public Utility Division ("PUD") Staff Witness Kathy J. Champion, Attorney General ("AG") Witness James Daniel, AG Witness Edwin Farrar, Wal-Mart Witness Steve Chriss, Oklahoma Hospital Association ("OHA") Witnesses John Athas and Kathleen Kelly and Citizens Potawatomi Nation ("CPN") Witness John Barrett.

In response to PUD witness Champion's recommendations, I ask the Commission to consider the impact of her recommendations on customers who pay more than their share of the cost of providing service when prices do not reflect the cost of service. These customers deserve to receive relief regardless of whether they use more than the average customer, have a better load factor, or have a lower cost to serve load profile than the average customer. "Gradualism" should not be used as an excuse to delay introduction of more accurate pricing to these customers and OG&E's proposal to establish three-part pricing is a move to address inequities in its pricing. The addition of a demand charge along with an increased customer charge more accurately reflects the cost of providing service to customers. I appreciate Ms. Champion's recognition that an increase to the customer charge is warranted, but believe her recommended $20 customer charge is still below cost. Further, Ms. Champion suggests that three-part pricing will negatively impact OG&E's energy efficiency efforts. The opposite is true. As described by witness Faruqui, three-part non time-differentiated tariffs are inherently more efficient than equivalent two-part non time-differentiated tariffs. Overpricing a product to achieve conservation is as inefficient as underpricing the same product. The demand charge properly assigns costs to customers, including to those who have higher demands with corresponding lower usage. Demand charges are proposed to ensure each customer's bills are aligned with the cost to provide them service.

I also address AG witness Daniel's arguments on OG&E's rate design related to his concerns about the impact of the Company's proposed rates on residential customers and opposition to the Company's PayGo pilot. Mr. Daniel proposes an alternate revenue distribution to OG&E's proposed rate increase level. While he lowers the revenue requirement to residential, general service, and power and light customers, his proposal appears overly harsh toward several rate classes, including OGP, PSND, PSD, and MP. I appreciate witness Daniel's recognition of the merits of a demand charge for residential customers.

I also respond to concerns raised by AG witness Farrar. The Company appreciates the support from Mr. Farrar for its SmartHours programs. OG&E does not believe there is a need to add to current SmartHours reporting requirements. In clarification, I point out that OG&E agrees with Mr. Farrar and has not proposed the addition of demand charges to SmartHours rates in this Cause. Regarding waivers to Commission rules for the PayGo prepayment plan, OG&E did not plan to request any waivers to the rules as it believes it received them with the initial approval of the program. If waivers were needed, I requested them. Mr. Farrar made eight

recommendations regarding the proposed PayGo program. I have addressed all eight of these recommendations.

Further, I address the responsive testimony of Wal-Mart witness Chriss. Witness Chriss misunderstands which costs are recovered by the PL-TOU SL5 demand charge. The PL-TOU SL5 demand charge is designed to recover the transmission and distribution demand function or "wires costs", not the production demand costs. The proposed charge of $5.76/kW compares favorably with the unit costs of $2.29/kW for transmission demand and $3.77/kW for distribution demand costs (a total of $6.06/kW). The production demand costs are recovered through the peak and the off-peak kWh charges, as well as the production energy costs. The monthly charge is designed to recover the customer related costs. OG&E offers another tariff to customers similar to Wal-Mart, the PL-1 SL5 tariff which has the larger demand charges requested by witness Chriss. OG&E believes it has reasonably and sufficiently differentiated the PL-TOU tariff from the PL-1 tariff using the unit cost data, and does not propose to redesign the PL-TOU to resemble the PL-1 tariff.

I address OHA Witnesses Athas and Kelly request for the aggregation of load through a single customer charge and a single demand charge, for adjacent hospital campus accounts. OG&E has already made the significant infrastructure investment in the distribution system required to serve the hospital campus facilities, or any large customer campus location for that matter. It is appropriate and described in Commission rules that utilities shall individually meter and bill each separate electric consuming facility (building). If at the time of the initial construction a hospital desired a single metering point and one bill, the Company could have designed its system to accommodate such a request. Further, at that time the customer could have made the distribution system investment, requesting to be relieved from paying for these investments now is not reasonable. OG&E's standard for demand measurement for billing is 15-minute demands and there is no reason to alter it for OHA members. These requests should be rejected. OHA requests the Healthcare Incentive Transition ("HIT") rider to return the additional revenue collected as a result of rates established at above 100% RROR applied to OHA accounts. On page 18 of OHA testimony asserts that this would be in line with the treatment to public schools and through the economic development incentive credit rider ("EDIC"). In this proceeding, OG&E is proposing to remove the PS benefit by increasing tariff price to the level of GS and PL equivalent tariffs. The EDIC is available to OHA members who meet the requirements of the economic development rider. It is not necessary to create another rider for hospitals. For these reasons, I would recommend that the OHA request for its HIT rider not be accepted. I recommended that the OHA requests for aggregation of load and rider not be accepted.

Finally, I respond to issues raised by CPN Chairman Barrett in his responsive testimony. Specifically, I note that OG&E is obligated to collect, report and remit a franchise fee on the gross receipts from the sale of electricity within such municipal limits. Regarding the request for distribution delivery services, as a vertically integrated electric utility, generation, distribution and transmission services are bundled into the cost of providing retail electric service. Retail customers within OG&E's service territory buy a bundled retail service.

John G. Athas and Kathleen A. Kelly

My name is John G. Athas. I am a Principal Consultant and Treasurer of Daymark Energy Advisors, Inc. This testimony is jointly sponsored by my colleague Kathleen A. Kelly, a Principal Consultant and Vice President of Daymark Energy Advisors, Inc. This testimony was filed on behalf of the Oklahoma Hospital Association ("OHA"). I testified regarding various aspects of Oklahoma Gas & Electric's ("OG&E") proposed revenue allocation and rate design, particularly with how these subjects impact members of the OHA and all major health care providers. I testified that although OG&E's proposal seems to recognize the need to move customer classes to more equitable rates of return, there are several elements that are either missing or insufficient to support the needs of Oklahoma's healthcare facilities. First, it is clear that OG&E has been unable to slow growth in spending, despite the expansion of its territory which has resulted in OG&E's ability to collect new additional revenue associated with the added customer base. It is also apparent that OG&E continues to propose class revenue assignments that do not represent a range of Relative Rate of Return ("RRoR") close enough to 100%, resulting in an ongoing situation where small and medium commercial accounts pay significantly more for their electricity than the cost of service study indicates is necessary. Lastly, OG&E does not recognize that today's customers, especially those in Healthcare services, are represented by more than one account or one meter. Rate Designs unnecessarily increase a 'customer's' cost with excess customer charges and demand charges that are higher than is representative of the customer due to the number of meters to serve the entire customer campus.

In light thereof, my testimony outlined OHA's recommendations as follows: First, a rider or tariff should be created that allows OG&E to earn the COSS indicated return on healthcare facilities while also improving the ability of healthcare facilities to transition its facilities and services to provide quality, accessible and affordable healthcare to Oklahomans. This Healthcare Incentive Rate Transition ("HIT") rider would credit each healthcare account with a percentage rate reduction that would be realized if their rate class had a RRoR of 100%. General Service Rates22 would receive a 2.6% incentive credit, Power and Light a 1.8% incentive credit, and Power and Light Time-of-Use a 4.2% incentive credit. Lastly, the Commission should issue a Final Order that allows adjacent multiple Healthcare Facilities accounts (meters) with the same ownership or resident organization to be billed as one customer, i.e. with on demand that is from the coincident hourly demands and one customer charge.

Mark E. Garrett

My name is Mark Garrett. My business address is 50 Penn Place, Suite 410, 1900 N Expressway, Oklahoma City, Oklahoma 73118. I am appearing on behalf of The Alliance for Solar Choice ("TASC"). The primary purpose of my testimony is to address, from a ratemaking perspective, the Application of Oklahoma Gas and Electric ("OG&E" or the "Company") to impose distributed generation ("DG") tariff changes in response to 2014 Senate Bill No. 1456 ("S.B. 1456").

[22] This would apply to all general Service Rate Schedules GS-GFB, GS-1, GS-TOU, GS-VPP, GS-CPP.

My testimony considers the proposed DG tariff changes in light of the application in Cause No. 201500274. It highlights how OG&E's current application not only fails to remedy the deficiencies TASC identified in Cause No. 201500274, but also requests penalties for DG customers that are contrary to S.B. 1456. As I discuss, when the Company uses fresh cost of service data—as opposed to the stale data relied on in Cause No. 201500274—it is clear that residential DG customers actually provide a subsidy to non-DG residential customers, and not the other way around. Accordingly, OG&E's proposed demand charge and increased fixed charges for DG customers violate the law. To comply with S.B. 1456, I recommend that the Commission reject those charges and maintain the status quo time-variant rate for DG customers. My testimony also addresses the broader implications of the Company's residential rate proposals, including substantial increases to customer fixed charges and a residential demand charge. OG&E seeks to impose a default three-part demand-charge rate design on Oklahoma ratepayers. This is an unwise and unprecedented formula that should be rejected.

I recommend that the Commission reject attempts to impose a discriminatory, mandatory rate structure on residential customers with distributed generation (proposed Schedule R-TOU-kW). The Company's DG proposal is contrary to S.B. 1456 and to standard ratemaking principles for the following reasons: (1) the Company fails to consider the costs and benefits of distributed generation to remedy the evidentiary deficiency of its application in Cause No. PUD 201500274 and, again, fails to demonstrate that residential customers with distributed generation are being subsidized by other customers within the same class; (2) the Company's Cost of Service Study shows that residential DG customers are providing a subsidy to other residential ratepayers – the opposite of shifting costs to those customers; and (3) the proposed R-TOU-kW violates S.B. 1456 because it would raise rates beyond what is necessary to recover the cost of service for residential customers with distributed generation.

I further recommend that the Commission reject the Company's proposal to make drastic rate design changes for residential customers, including those with distributed generation. These changes include the establishment of a three-part rate for standard residential customers, with the unprecedented imposition of a demand charge on these customers, and the doubling of the customer charge. I recommend that these proposed changes be rejected for the following reasons: (1) residential customers are wholly unaccustomed to demand charges, so it is not advisable from a policy perspective to thrust an untested and unprecedented rate experiment on the majority of the Company's residential customers; (2) non-coincident demand charges do not align with cost causation principles and do not reflect the time-specific costs associated with energy consumption; (3) average residential customers generally lack the specialized awareness required to manage demand and cannot readily access the costly equipment necessary to assist in controlling maximum demand; (4) demand charges have the prospect of being punitive and discouraging of beneficial behavior for customers that manage their demand well for 99% of the month, but get hammered for one 15-minute period where usage spikes (perhaps for reasons beyond their control); (5) the proposal to double the customer charge inappropriately expands the category of customer-related costs to elements of the distribution grid that vary with the amount of usage, not with the number of customers; and (6) the doubling of the customer charge weakens the price signal to conserve electricity.

In my rebuttal testimony, I briefly replied to the positions taken by witnesses of the Public Utility Division ("PUD" or "Staff") and the Office of the Attorney General ("AG") on OG&E proposed residential rate design in this cause. In particular, I respond to the testimony of PUD witness Kathy J. Champion and AG witnesses Edwin C. Farrar and James W. Daniel with respect to their positions on the Company's proposal to increase customer charges and to impose a demand charge as part of the standard service tariff.

John A. Barrett

My name is John A. Barrett. I am Tribal Chairman of the Citizen Potawatomi Nation, a Federally Recognized Native American Tribe headquartered in Shawnee, Oklahoma. Our tribal office complex is located at 1601 Gordon Cooper Drive, Shawnee, Oklahoma 74801.

Intervention in a matter at the Oklahoma Corporation Commission by a Federally Recognized Native American Tribe is unusual. It is important for this Commission to know our history and composition of the Citizen Potawatomi Nation.

The Potawatomi are among the Algonquian-speaking people who occupied the Great Lakes region from prehistoric times through the early 1800s. During the Removal Period of the 1830s, the Mission Band, today known as the Citizen Potawatomi Nation were forced to leave their homelands in the Great Lakes and then eventually moved to Oklahoma Territory to purchase reservation lands in the late 1800s. The Nation was a party to more than forty treaties, including the 1867 Treaty with the Potawatomi, in which it was recognized as a sovereign nation under the protection of the laws, jurisdiction, and government of the United States of America.

The Nation's original reservation in Indian Territory encompassed 900 square miles with boundaries described as an area spanning from north of the Canadian River, South of the North Canadian River, East of the Indian Meridian, and west of the Seminole County Line, Oklahoma.

Today, the CPN is considered one of the most progressive Native governments in a state of 39 federally recognized tribes; it possesses the managerial, technical, and administrative capability to provide general government services to Native American community residents in economic/business development, social and health service delivery, and educational assistance. Under sound, consistent and innovative leadership, the Tribe continues to strive to meet its long-range goals of economic development and self-sufficiency. About 12,000 tribal members live in Oklahoma, while the remainder of the 32,500 members are located throughout the United States, plus in at least five foreign countries. The Nation is governed under the Constitution of the Citizen Potawatomi Nation, as originally adopted in 1938 and amended in 1985, and subsequently amended in 2007. The 2007 constitutional reform effort has been featured among the exhibits of the Smithsonian Institution's National Museum of the American Indian as an example of excellence in self-governance. The Constitution provides framework for our three-branched government, consisting of an Executive, Legislative and Judicial branch that oversees the operations and administration of tribal government.

The economic prosperity of the Nation has been used to provide services to its members and to the surrounding community. CPN social and human services activities include job

placement programs, emergency services for families and children, tribally funded health care services, child care, youth mentoring, nutritional services for pregnant women, nutritional services for children, emergency assistance for utility bills, food and college preparation services. Our CPN elderly service program provides meals and social activities to Native Americans within the CPN jurisdiction.

All programs offered by Employment and Training target the economically disadvantaged, unemployed and under-employed. Services are rendered on an un-met need basis with available funding. Counselors are available to assist with resume writing, job referrals, interview tips, job placement and other employment related services.

The Citizen Potawatomi Nation Women Infant, Children program provides supplemental nutritious foods, health and nutrition education, referrals, and nutrition and breastfeeding counseling for eligible pregnant, breastfeeding, and postpartum women as well as infants and children under the age of five years. The program is designed to positively impact prenatal nutrition, infant birth weight, iron deficiency anemia and early childhood nutrition and cognitive development. WIC complies with all applicable Federal and state agency mandates. CPN WIC serves approximately 1,200 participants at its three permanent agency/clinic sites and three mobile satellite sites in central Oklahoma.

In addition, Citizen Potawatomi Nation operates other business interests that are of benefit to tribal and non-tribal members living in Pottawatomie County. Rural Water District 3 is the largest rural water district in Pottawatomie County. RWD 3 serves almost 1,000 customers and its service area includes 60 percent of Pottawatomie County with more than 285 miles of line. RWD 3 serves the towns and schools of Asher, Wanette and Dale. RWD 3 is also a partial water supplier to Tecumseh. CPN began operating the water district in 2007 and has expanded the infrastructure of the system to provide both improved water quality and quantity in rural Oklahoma. While doubling the number of customers and water treatment capacity, a second water plant is now part of the district and three new towers have been built to improve service. This service is available to Native Americans and non-natives.

The Citizen Potawatomi Nation Tribal Police Department is responsible for protecting and patrolling the 900 square mile area that is within the Citizen Potawatomi Nation jurisdictional boundary. The Cross-deputation program also allows Citizen Potawatomi Nation police officers to have jurisdiction in Pottawatomie County. The department also provides a full-service dispatch center in conjunction with the Pottawatomie County Sheriff's Department and the Tribal Police departments of the Kickapoo, Sac and Fox, and Absentee Shawnee Indian Nations. In 2015, CPN began providing dispatch services for all emergency services in Pottawatomie County with the exception of McLoud and Shawnee. Again, this service is available to Native Americans and non-natives.

It would be difficult to succinctly summarize all of the Nation's businesses. The Nation owns and operates the Grand Casino Hotel & Resort at the intersection of Interstate 40 and State Highway 102, a major casino complex employing over 900 workers, the majority of whom are non-tribal members. The Nation has invested in and developed additional enterprises on its tribal lands. Thus, located on tribal lands outside the grounds of the Grand Casino Hotel &

Resort, the Nation has created, owns and operates: FireLake Golf Course, Firelake Bowling Center, FireLake Mini-Putt Golf, FireLake Designs (specializing in screen printed garments), a tribal radio station, FireLake Entertainment Center (a separate casino), FireLake Arena (an event venue), FireLake Discount Foods (which is vertically integrated with CPN-owned agricultural enterprises), FireLake Express Grocery, FireLake Corner (Convenience) Store, FireLake Pizza, FireLake Fry Bread Taco, and FireLake Grand Travel Plaza. The Nation has recently opened a third grocery store, FireLake Express Grocery Store No. 2, near McLoud, Oklahoma.

In addition, the Nation owns the First National Bank and Trust Company, with branches statewide, including a local branch on tribal land. The Nation has invested in the development of the Iron Horse Industrial Park, an international trade zone located on tribal lands. The Nation looks forward to further industrial development.

Beyond the positive economic impact of the Nation's growing businesses on neighboring communities, the Nation regularly and substantially contributes to these communities in many forms that, again, would be difficult to adequately summarize. The Nation also makes regular and substantial monetary contributions to local charities and local governments and cooperates with such charities and governments to improve the quality of life in the communities surrounding the Nation, exceeding $2,000,000 annually.

The Nation is a large user of electricity, and its members are also users of electricity. From our tribal housing complex to our largest facility, the Grand Casino and Hotel Complex, our billings averaged more than 24.6 million kilowatt hours of electric usage resulting in 2015 annual billings in excess of $2,250,000. We are mindful of electric energy usage but are always seeking ways to better manage that major expense. This proposed rate increase, an additional $92 million, will impact our business operations and will also impact our members living in the OG&E service area and our patrons at the various businesses on the Nation's lands.

The Nation has already examined a number of energy efficiency measures to address energy usage. From use of spray foam insulation in a number of our buildings, to geothermal systems at the Grand Casino complex and tribal housing project, to solar roof-top panels as an added measure energy efficiency measure at the tribal housing complex, the Nation continues to examine other energy efficiency measures that will reduce or control electric usage.

Our current rate of $0.061 per kilowatt hours is excessive for a consumer of our size. Other Federally Recognized Native American Tribes have rates that are much lower than that paid by the Citizen Potawatomi Nation, and we believe that is fundamentally unfair.

While OG&E supplies the bulk of the electricity consumed on tribal lands, we also are provided electric service by Canadian Valley Electric Cooperative and a municipal system owned by the City of Tecumseh. Many of our members live in OG&E's service area, but others live in areas served by electric cooperatives or by municipal electric systems. Sovereignty provides an Indian Tribe with alternatives that may not be available to other entities. Since we are not bound by territorial rules and regulations, we can examine a number of different ways to select our provider of electricity or to supplement our electric supply using new and innovative techniques.

The simplest approach would be to continue work with the utility, in this case OG&E, to provide our electric needs. Other Indian tribes in Oklahoma have continued to work with their existing electric provider but have also created a tribally approved mechanism, the tribal utility authority, to diversify their electric energy supply. Using a business entity created by a legislative act, these tribes have created a Tribal Utility Authority which works with electric suppliers to deliver the power needed for their facilities. Primarily directed to electric usage at tribally owned buildings, offices and other enterprises, a utility authority is charged with the management and operation of this activity. To that end, the Nation has created the Citizen Potawatomi Nation Tribal Utility Authority. It could manage the Nation's utility operations and coordinate those supplemental activities.

A tribal utility authority is a governmental entity created by an Indian tribe's governing body. In Oklahoma, Tribal Utility Authorities have been created by several tribes. The statutory language of each tribe's authorizing legislation provides the structure under which they operate. For example, the Osage Nation's legislation provides the Authority's regulatory jurisdiction and identifies electricity, gas, water, sanitation, telecommunications wastewater treatment and renewable energy for regulation and oversight, while others are more limited.

In 1998, the Federal Energy Regulatory Commission ("FERC") disclaimed jurisdiction over a tribal utility authority, wholly owned by a federally recognized Indian tribe, because the tribe's TUA performs inherent governmental functions and thus falls within the exemptions provided by Part II, Section 201 of the Federal Power Act. Thus, FERC recognized the Tribe is an instrumentality of the "United States, a State or any political subdivision of a state" and performs an inherent governmental function, where the funds will be utilized by the tribe on behalf of the government and in performance of governmental functions and activities. Following that decision, FERC issued a disclaimer over a filing by Chickasaw Nation Industries, Inc. of Oklahoma seeking permission to make wholesale sales, using the same rationale.

We also want to examine better use of our generation facilities. Pursuant to the National Indian Gaming Commission's regulations, back-up generation is a requirement for operation of our gaming facilities. We currently have sufficient generation in place to satisfy those requirements. But, there may be better ways to utilize this generation by examining the right fuel mix for their operation and even looking at a more centralized generation facility to serve the gaming operations and also other tribal complex facilities. In addition, we are looking at how this generation could be used to provide stand-by, back-up or supplemental power as a part of the new Iron Horse Industrial Park.

We are also examining energy delivery options. Adding a micro-grid system to serve our facilities will be examined to determine if that enhances out delivery of electricity to our facilities. While this is a concept that has not yet been used in our state, other states are beginning to recognize that having the ability to purchase, for example, wind energy from a developer and transmitting the energy on the grid to a wholesale substation near or at your business location might provide lower electric costs by use of a micro-grid. We may also lower costs by using battery stored electricity at peak times.

Duplicating a utility's existing system is not an efficient use of resources but if a customer like CPN could be provided access to the incumbent utility's distribution facilities to supplement electric energy it has purchased or generated, while paying distribution charges the utility charges itself, we think this concept can reduce customer expense while providing revenue to the utility for the use of its facilities that are now in place.

The natural gas industry and the communications sector have already undergone major changes in recent years. I think similar changes will occur for the electric industry because alternative sources of electric energy are now becoming competitive. A distributed energy resource, for example, in the form of a small natural gas generating system that can be located adjacent to a large consumer's office, manufacturing facility, or Casino and Resort will provide savings for those customers. Wind resources continue to be built in our state that provide opportunities to purchase long-term supplies of electricity at prices that are competitive. Solar roof-top and commercial solar systems are going to be a part of Oklahoma's future because the price is already competitive in Oklahoma and across the country. We want to be a leader in these technology advancements for our Tribe but also for our state.

Any business has to manage its costs to continue to be successful, and the Nation has to consider its operating expenses so that it can continue to provide essential services to its members and the surrounding community. We want to work with OG&E and other utility providers to obtain reliable utility services at a reasonable cost.

James R. Dauphinais

Mr. Dauphinais, a Managing Principal of Brubaker & Associates, Inc. ("BAI"), filed testimony in response to the application of Oklahoma Gas & Electric Company ("OG&E" or "Company") filed in the captioned cause. Mr. Dauphinais testified as to his education and professional experience. Mr. Dauphinais testified he holds a degree in engineering from the University of Hartford and has completed graduate level courses through the Engineering Outreach Program of the University of Idaho. He testified that he worked for 12 years in the transmission planning department of Northeast Utilities Service Company, has been employed the past 18 years by BAI and is a Managing Principal of BAI. Mr. Dauphinais testified that his past work has included, but not been limited to, utility rates, transmission planning and transmission line routing.

In his responsive testimony, Mr. Dauphinais specifically addressed two issues:

- The extension of OG&E's SPP Cost Tracker ("SPPCT"); and
- OG&E's Capital Expenditures for Transmission Projects.

With respect to the extension of OG&E's SPPCT, Mr. Dauphinais first discussed the prerequisites that should be met from a policy perspective prior to the Commission granting or extending a rate adjustment rider like the SPPCT. He noted that such riders allow a utility to pursue single issue ratemaking with respect to the expenses and revenues tracked by that rider. This allows the utility to receive additional revenue in rates due to changes in tracked expenses and revenues without consideration of whether that utility would be experiencing offsetting

changes in expenses and revenues that are not tracked. He testifies such riders disrupt the synchronism among revenues, expenses and rate base.

Mr. Dauphinais also notes such adjustment riders eliminate the inherent incentive a utility has to minimize expenses and maximize revenues between base rate proceedings. He notes this inherent incentive acts over time to keep rates lower than they otherwise would be. He indicates that when a utility is allowed to track certain expenses and revenues through an adjustment rider, it can become indifferent or less vigilant with respect to minimizing those expenses or maximizing those revenues since it knows it can pass on to ratepayers any change in the expenses and revenues in the rider. Finally, he notes that while prudence review still provides some incentive to a utility, it does not provide the same incentive, in part, because it is very difficult to prove prudence and that this difficulty is even more of a problem for riders due to the expedited nature of their reconciliation proceedings.

Mr. Dauphinais specifically identifies the following three prerequisites that should be met for adjustment riders such as OG&E's SPPCT. The utility would need to show that the anticipated changes in the expenses or revenues that would be tracked by the proposed rider are:

- Large enough to present a threat to the financial well-being of the utility;
- Volatile; and
- Not able to be reasonably managed by the utility.

Mr. Dauphinais proceeds to explain why these prerequisites should be met. First, he notes that rate adjustment riders should only be used when the expected possible changes to the revenues and expenses in question are extraordinary enough such that normal ratemaking would not provide a reasonable opportunity for the utility to earn its authorized return. He testifies that the three prerequisites act together to ensure the revenues and expenses that are proposed to be tracked are indeed extraordinary enough to justify the granting of such a rider that periodically adjusts rates.

Mr. Dauphinais states that the first prerequisite ensures that anticipated changes in the revenues and expenses to be tracked are large enough that they do present a significant financial challenge to the utility, assuming they cannot reasonably be managed by that utility. The second prerequisite, volatility, limits tracking to circumstances where the anticipated changes in the magnitude of the expenses and revenues are large, difficult to predict, and could potentially harm both the utility and ratepayers under traditional ratemaking if they cannot be reasonably managed by the utility. This prerequisite ensures that there are benefits to both the utility and ratepayers from tracking the expenses and revenues that cannot be reasonably managed. The third prerequisite helps to ensure that a utility is not seeking such a rider for anticipated changes in revenues and expenses that the utility could reasonably manage through other means available to it such as hedging, forward bilateral contracting, fully utilizing RTO stakeholder processes, fully utilizing remedies at the Federal Energy Regulatory Commission ("FERC") and/or the timing of base rate relief filings.

Mr. Dauphinais indicates that other regulatory jurisdictions have required utilities to meet the three prerequisites discussed above, or other very similar prerequisites, prior to the granting

of a periodically adjusting rider. He provides evidence of this requirement by referring to a September 2009 Report titled "How Should Regulators View Cost Trackers?" prepared by Ken Costello, a Principal of the National Regulatory Research Institute ("NRRI"). Mr. Dauphinais cites to certain statements from the NRRI report affirming that rate adjustment rider mechanisms have historically only been approved under extraordinary circumstances, which consist of costs that are outside the utility's control, unpredictable and volatile, are substantial and recurring, and to prevent significant financial harm to the utility due to unforeseen circumstances at the time of the previous base rate case. The NRRI report was attached to Mr. Dauphinais' testimony as Exhibit JRD-1.

Mr. Dauphinais testifies that the Commission's previous approval of an adjustment rider for OG&E does not provide a basis for the automatic continuation of that rider. He states that the applicant in a base rate proceeding seeking to continue the use of a rate adjustment mechanism should still be required to demonstrate that the prerequisites described above have been met.

Mr. Dauphinais' testimony continues with a discussion of OG&E's SPPCT. He states that the SPPCT is a rate adjustment rider that currently tracks and fully recovers the Company's SPP Schedule 11 Base Plan transmission expenses and credits associated with transmission projects constructed by non-OG&E transmission owners within SPP. Mr. Dauphinais presents the budgeted Oklahoma-jurisdictional revenue requirement for the SPPCT each year from OG&E's annual SPPCT redetermination filings for 2011 through 2015, and highlights the fact that it has risen dramatically since its inception in 2011. Additionally, Mr. Dauphinais compares the actual budgeted revenue requirement for 2011 through 2015 to the annual amounts presented in OG&E Witness Donald Rowlett's direct testimony in Cause No. PUD 201000146. He notes that the annual amounts from the redetermination filings have been consistently higher than the amounts expected when the SPPCT was first proposed in 2010. Further, the consistently higher-than-anticipated revenue requirements do not indicate inherent volatility, but serve to reinforce the need for OG&E to be highly vigilant in ensuring that these charges are truly necessary and are incurred at lowest reasonable cost.

Mr. Dauphinais proceeds to reiterate that OG&E has an obligation to provide reliable service to retail electric customers at lowest reasonable cost, as OG&E's customers bear the responsibility of paying for these costs. He also suggests that as a transmission customer under the SPP Open Access Transmission Tariff, OG&E is in the best position to manage these costs. Lastly, Mr. Dauphinais indicates that in its evaluation of a possible extension of the SPPCT, the Commission should consider OG&E's past behavior with respect to reasonably managing these costs within the bounds of its ability in the SPP stakeholder process and at the FERC.

Mr. Dauphinais indicates that the SPPCT was not granted to OG&E for perpetuity by the Commission's orders and the associated stipulations. He notes that the "term" paragraph of the first sheet of tariff language for the SPPCT requires the rate adjustment be reviewed for extension, modification, or termination during OG&E's 2013 rate case. However, since a 2013 rate case did not occur, the aforementioned review of the SPPCT applies in the current proceeding. Mr. Dauphinais recognizes that OG&E has in effect requested an extension of the SPPCT by continuing to include it in the proposed tariff and by proposing to change the "term"

paragraph of the tariff language to indicate that the SPPCT will remain effective until modified or terminated by the Commission.

Mr. Dauphinais states that OG&E has not provided evidence in its direct testimony that supports the extension of the SPPCT. He states that OG&E has not presented any direct testimony that demonstrates that the nature of the expected future changes in the expenses and credits that are recovered through the SPPCT will meet the prerequisites for those expenses and credits to continue to be tracked in a rate adjustment mechanism. Specifically, OG&E has not demonstrated that changes in these expenses and credits in the coming years will be: (i) large enough to present a threat to the financial well-being of the utility, (ii) volatile, and (iii) not able to be reasonably managed by the utility.

Mr. Dauphinais also testifies that it is important to review the steps that OG&E has taken and is taking on an ongoing basis to minimize the expenses being tracked and maximize the revenues being tracked. He states that OG&E should have demonstrated that on an ongoing basis, it has taken all reasonable steps at SPP and FERC to ensure that its Schedule 11 charges (net of credits) for projects constructed by non-OG&E transmission owners within SPP are necessary, selected on the basis of lowest reasonable cost, prudently constructed and reasonably allocated to OG&E. Mr. Dauphinais proceeds to testify that OG&E has failed to make this demonstration, and recommends that the Commission discontinue the SPPCT.

Mr. Dauphinais indicates that his recommendation does not deny OG&E cost recovery of the charges and credits that it had proposed to recover through the SPPCT. Instead, it only changes the method of cost recovery. Specifically, these charges and credits would be recovered in base rates, with a cost allocation to rate classes similar to what would have been applied under the SPPCT. This would incent OG&E, between base rate cases, to minimize expenses and maximize revenues leading to a lower cost to serve OG&E's customers.

Mr. Dauphinais concludes his testimony with a discussion of OG&E's capital expenditures for transmission projects. He states that OG&E has indicated that it has incurred large capital expenditures since its last base rate case. He points out that while OG&E Witness Donald Rowlett stated that $1.6 billion of a $2.2 billion investment in utility infrastructure is not currently being recovered from Oklahoma customers through rates or existing riders, these really appear to be total Company investment numbers rather than Oklahoma-jurisdictional numbers. Additionally, Mr. Dauphinais discusses inconsistencies between the pre-construction cost estimates for certain transmission projects, the original costs and the actual costs reported in OG&E's filing, and provided in data responses to OER. He indicates that pending OG&E's responses to certain data requests, he may need to supplement his responsive testimony and recommend prudence disallowances with respect to OG&E's proposal to recover the Oklahoma-jurisdictional OG&E share of these costs in base rates.

At the end of his testimony, Mr. Dauphinais recommends that OG&E's SPPCT be discontinued, and that the associated expenses and credits be reflected in base rates with a cost allocation similar to that which would have applied under the SPPCT. He states that OG&E has not presented evidence showing that the nature of the expected future changes in the expenses and credits that are recovered through the SPPCT will meet the prerequisites for those expenses

to continue to be tracked in a rate adjustment mechanism. Additionally, OG&E has not demonstrated that it is actively taking all reasonable steps to ensure expenses recovered through the SPPCT are necessary and at lowest reasonable cost.

Mr. Dauphinais filed supplemental testimony in response to the application of OG&E filed in the captioned cause. Mr. Dauphinais testified that he is the same OER witness that filed responsive testimony on behalf of OER on March 21, 2016.

In his supplemental testimony, Mr. Dauphinais addressed an outstanding question from his responsive testimony regarding the reasonableness of certain OG&E capital expenditures for transmission projects that OG&E proposes to include in its Oklahoma - jurisdictional rate base and recover in its proposed revenue requirement.

Mr. Dauphinais indicates that through the discovery process, OG&E identified four rate base additions with investment costs of $50 million or more. These include the following:

- Woodward EHV – Hitchland 345 kV Transmission Line ("Woodward-Hitchland");
- Woodward EHV – Thistle/Comanche County 345 kV Transmission Line ("Woodward-Thistle");
- Seminole – Muskogee 345 kV Transmission Line ("Seminole-Muskogee"); and
- Woodward EHV – Tuco 345 kV Transmission Line ("Woodward-Tuco").

Mr. Dauphinais questioned whether the large difference between the original estimated cost for these projects and the actual cost for some of these projects was prudently incurred. He also notes that all four of these projects are SPP Base Plan transmission projects that are subject to regional cost allocation under the SPP Open Access Transmission Tariff, and as a result OG&E only proposes to place the Oklahoma-jurisdictional portion of the projects not covered by other load serving entities within SPP into OG&E's base rates in this proceeding.

Mr. Dauphinais stated that resolution of the prudence question depended on OG&E's response to then outstanding Data Request OER 3-1. This response was served after 5 PM CDT on March 21, 2016, which was the filing deadline for responsive testimony. Additionally, OG&E held back from its response a document that it deemed as Highly Sensitive Confidential. Mr. Dauphinais testifies that on April 7, 2016, he traveled to OG&E's Corporate Offices to review the document. He indicates that based on his review of that document, along with a reconciliation of the rest of OG&E's response to Data Request OER 3-1 and information on the SPP website, a prudence disallowance was in order.

Mr. Dauphinais proceeded to testify that OG&E's statements with respect to the original estimated cost of the projects are in error and that OG&E has not produced evidence demonstrating that the additional cost incurred above the original estimated cost for these projects was prudently incurred.

Mr. Dauphinais describes the prudence standard. He indicates that prudence addresses the reasonableness of the actions taken, based on information known, or knowable at the time that the decision was made. He states that a utility should retain the information and analyses

upon which its actions were based, so that the reasonableness of those actions can be reviewed when the recovery of the costs in question is later sought through the utility's rates. He also states that the failure to produce such supporting information and analyses during such a review can alone be a basis for a prudence disallowance.

Mr. Dauphinais states that the Seminole-Muskogee, Woodward-Thistle and Woodward-Tuco projects have a much higher actual cost than originally estimated.

Mr. Dauphinais testifies that the Woodward-Thistle project originated as the Woodward to Comanche County 345 kV project, and it would have been 55 miles in length, with an estimated cost of $108.2 million ($97.4 million OG&E and $10.8 million Western Resources). In September 2010, OG&E notified SPP that it was changing the cost estimate for its portion of the Woodward to Comanche project from $97.4 million to $134.4 million due to an agreement to use an alternate route to arrive at a substation in Kansas that was ultimately named Thistle. In the end, this increased the length of this project from 55 miles to 107 miles. Mr. Dauphinais proceeds to testify that OG&E has not provided any information or analyses that supports that this decision was reasonable based on information known, or knowable, at the time the decision was made. Further, as part of the review of the Woodward-Thistle transmission project, Mr. Dauphinais reviewed a routing study prepared by Burns & McDonnell, which includes the increased length of the transmission line. Mr. Dauphinais highlights the fact that this study was prepared after OG&E decided to add to the route of the proposed project by changing it from Woodward to Comanche to Woodward to Thistle, therefore it does not support the reasonableness of OG&E's decision to propose and/or agree to the change that added length to the OG&E portion of this project.

Mr. Dauphinais recommends that the additional cost that OG&E incurred due to its decision to propose and/or agree to the route change to the Woodward-Thistle transmission project was imprudently incurred. OG&E failed to produce information and analyses that support the reasonableness of its decision.

As a result, Mr. Dauphinais recommends that the net plant and revenue requirement that OG&E proposes to include in its Oklahoma-jurisdictional rates for the Woodward-Thistle transmission project be scaled down by 70.5%, which is the ratio of the original estimated cost of the project of $97.4 million to the final actual cost of the project of $138.1 million. Mr. Dauphinais states that his recommendation would lower OG&E's revenue requirement by $571,185.

Mr. Dauphinais also recommends that the additional costs above the original estimated cost for the Seminole-Muskogee and Woodward-Tuco projects be found to be imprudently incurred. He states that despite the actual cost for these two projects being more than 25% higher than their original estimated cost, OG&E provided no explanation, analyses, studies or correspondence supporting these additional costs as being reasonably incurred.

As in the case of the Woodward-Thistle project, Mr. Dauphinais recommends that a similar scaling factor method be used to adjust the rate base and revenue requirements for the Seminole-Muskogee and the Woodward-Tuco projects. Mr. Dauphinais recommends revenue

requirement reductions of $616,348, and $644,286 for the Seminole-Muskogee and the Woodward-Tuco projects, respectively.

Mr. Dauphinais states that his recommendations with respect to the transmission projects identified above will lower OG&E's proposed revenue requirement by about $1.8 million.

Geoffrey M. Rush

Geoffrey M. Rush is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission and filed Responsive Testimony on March 21, 2016, in Cause No. PUD 201500273. The purpose of Mr. Rush's testimony is to present PUD's recommendation for his assigned areas in response to the Application filed by Oklahoma Gas and Electric Company.

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

Mr. Rush recommended PUD Adjustment No. 6, which will decrease Payroll Expenses by the amount of $2,689,594. This would decrease OG&E's pro forma adjustment to test-year labor expense from $5,271,733 to the amount of $2,582,139. This adjustment recognizes six months post test year data, which captures effects of developments within that six-month period after the test year. In the area of Payroll Taxes, Mr. Rush recommended Adjustment No. 7, which would decrease Payroll Taxes in the amount of $178,517, reducing the Company's pro forma adjustment increase in Payroll Tax expenses to the amount of $181,102. The combined amount of these two PUD labor-related adjustments represents a total reduction of $2,868,111. PUD believes that the adjustments made are fair, just, reasonable and in the public interest.

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

David J. Garrett

David Garrett, for the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or the "Commission"), filed Responsive Testimony on March 21, 2016. The purpose of Mr. Garrett's testimony is to review cost of capital and depreciation in response to the Application of Oklahoma Gas and Electric Company ("OG&E" or "Company").

Cost of Capital

With regard to cost of capital, Mr. Garrett testified to the following key points:

1. Basing the authorized rate of return for OG&E on orders and settlements from other jurisdictions fails to comply with the Supreme Court's standards governing this issue. Instead, the authorized rate of return should be based on the Company's cost of capital.

2. When the authorized rate of return exceeds the cost of capital, it results in an inappropriate transfer of excess wealth from customers to shareholders.

3. The Company's cost of equity must lie between a "floor" and a "ceiling," where the floor is the risk-free rate and the ceiling is the required return on the market portfolio. Currently, the floor is about three percent and the ceiling is about eight percent.

4. The models used in this Cause indicate the Company's cost of equity is about 6.2 percent.

5. When assessing the proper capital structure, it is not appropriate to merely consider the capital structures of other regulated utilities or the Company's test-year capital structure. OG&E's optimal capital structure consists of about 60 percent debt and 40 percent equity.

Mr. Garrett testified that OG&E's cost of capital is comprised of two components: debt and equity. While the cost of debt is determined by fixed, contractual interest payments, the cost of equity must be estimated through financial models. Mr. Garrett employed two widely-used financial models, the Discounted Cash Flow Model ("DCF Model") and the Capital Asset Pricing Model ("CAPM"), to estimate the Company's cost of equity. Finally, Mr. Garrett conducted an analysis to estimate the Company's optimal capital structure.

Mr. Garrett testified that 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 successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF model, which is what Mr. Garrett used in his analysis. All else held constant, the Quarterly Approximation DCF Model results in the highest cost of equity estimate for the utility in comparison to other DCF models. The average DCF result of the proxy companies using the Quarterly Approximation DCF model is 6.56 percent.

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

the ERP used in his CAPM analysis. The average CAPM result for the proxy group was 5.85 percent.

Mr. Garrett testified that capital structure refers to the way a firm finances its overall operations through external debt and equity capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. Because interest expense is deductible, increasing debt also adds value to a firm by reducing its tax obligation. Using technical analysis rather than simply looking at the capital structures of the proxy group, Mr. Garrett estimated the optimal capital structure for OG&E, which consists of about 60 percent debt and 40 percent equity.

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

Mr. Garrett argues that Mr. Hevert's estimate for the equity risk premium ("ERP") is extremely high. Mr. Garrett conducted an analysis of the ERP using three widely-accepted methods. Mr. Hevert's ERP estimate, which is as high as 10.32 percent, is about twice as high as the ERP estimated by many other experts. Mr. Garrett recommends that the Commission disregard Mr. Hevert's CAPM results due to his inappropriately high estimate for the ERP. Also, Mr. Garrett argues that Mr. Hevert's Bond Yield Plus Risk Premium Analysis is inappropriate for several reasons. Thus, Mr. Garrett recommends the Commission disregard Mr. Hevert's Bond Yield Plus Risk Premium analysis.

Mr. Garrett also testified that in addition to having low levels of market risk, OG&E also has low levels of firm-specific business risk. Investors do not expect a return for assuming firm-specific risk because such risk can be eliminated through diversification. Only market risk is rewarded by the market. Therefore, any discussion of the Company's firm-specific business risks in this Cause, while perhaps relevant to other issues in this rate case, should have no meaningful effect on the cost of equity estimate.

Mr. Garrett recommends that the Commission not allow "flotation" costs as argued by Mr. Hevert. Flotation costs generally refer to the underwriter's compensation for the services it provides in connection with the securities offering. Mr. Garrett believes the Commission should not allow recovery of flotation costs in this case for the following reasons: 1) flotation costs are not actual "out-of-pocket" costs, 2) the market already accounts for flotation costs, and 3) it is inappropriate to add any additional basis points to a proposed authorized return that is already far above the true cost of equity.

Mr. Garrett requested the Commission make the following findings with regard to cost of equity, cost of debt, capital structure, and the authorized rate of return:

Cost of Equity

1. The Commission finds that, pursuant to standards expressed by the Oklahoma Supreme Court, the authorized return on equity for a regulated utility should be based on the utility's cost of equity as estimated through various financial models, and should not be based on the returns awarded in other jurisdictions.

2. The Commission finds that PUD's recommended authorized return on equity of 9.25 percent should be adopted, and that although such an authorized return on equity would be significantly higher than OG&E's cost of equity, it is nonetheless based on the Company's cost of equity and is fair under the circumstances, as it represents a gradual, rather than abrupt, move toward the true cost of equity.

Cost of Debt

3. The Commission finds that OG&E's cost of debt of 5.62 should be adopted.

Capital Structure

4. The Commission finds that as a surrogate for competition, it has the authority to impute a proper capital structure for any regulated utility when the utility's capital structure does not reflect one that would exist in a competitive environment.

5. The Commission finds that regulated utilities do not have a financial incentive to operate at a capital structure that would exist in a competitive environment and, thus, the capital structures of other regulated utilities do not necessarily indicate capital structures that would exist in a competitive environment.

6. The Commission finds that just as competitive firms seek to minimize their weighted average cost of capital, the utility has the obligation to seek the lowest reasonable weighted average cost of capital.

7. The Commission finds that OG&E's current debt ratio of 46.69 percent is significantly less than a debt ratio that would exist for the Company in a competitive environment, and that this low debt ratio increases OG&E's cost of capital beyond its lowest reasonable level.

8. The Commission finds that although OG&E's actual capital structure is within the discretion of Company management, the Commission will impute a capital structure in future rate cases that seeks [sic] to bring the Company's weighted average cost of capital to a more reasonable level.

9. The Commission finds that OG&E's proposed capital structure is adopted.

Awarded Rate of Return

10. The Commission finds that, pursuant to the Supreme Court's standards, the rate of return authorized in any case should be based on the utility's actual weighted average cost of

capital as calculated through its cost of equity, cost of debt, and optimal capital structure, and should not be based on the returns awarded in other jurisdictions.

11. The Commission finds that PUD's recommended awarded rate of return of 7.56 percent should be adopted, and that although this awarded rate of return is significantly higher than OG&E's weighted average cost of capital, it is nonetheless based on the Company's weighted average cost of capital and is fair under the circumstances, as it represents a gradual, rather than abrupt, move towards true cost of capital.

Depreciation

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

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

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

calculate the terminal net-salvage percentages, Mr. Garrett divided the estimated demolition cost for each unit (less the contingency factor), by the estimated amount of terminal retirements.

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

Mr. Garrett testified that the Company had not met its burden of proof with regard to terminal net salvage because it did not provide a decommissioning study. Thus, PUD disallowed half of the proposed terminal net salvage and recommended that the Company file a comprehensive decommissioning study in its next rate case. Mr. Garrett also testified that the Commission should adopt 30-year probable lives for the Company's wind generating units, instead of 25-year probable lives. The probable life of a wind turbine may be 25 years, but the probable life of the entire generating unit is likely much longer.

Jason C. Chaplin

Mr. Chaplin is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Mr. Chaplin filed responsive testimony on March 21, 2016. The purpose of Mr. Chaplin's testimony is to provide PUD's recommendations and analysis pertaining to the request by Oklahoma Gas and Electric Company ("OG&E" or "Company") to adjust the recovery of certain Southwest Power Pool ("SPP") transmission costs through its transmission riders and base rates. Mr. Chaplin also reviewed OG&E's proposed adjustments to wind power expense and underground vault expense.

OG&E is proposing one rate base adjustment and four operating income adjustments related to OG&E's SPP expenses, one operating income adjustment for wind power expense, and one operating income adjustment related to the underground vault expense. The table below summarizes these seven proposed adjustments:

Adjustment	Amount	Schedule/WP Reference
Transmission Expense Recovered From other Load Serving Entities (LSEs)	($655,558,467)	Schedule B/WP B-3-12
SPP Transmission Cost Tariff	$628,295	Schedule H/WP H-2-30
Expense Recovered from LSEs	($33,006,737)	Schedule H/WP H-2-33
SPPCT Rider	($39,344,302)	Schedule H/WP H-2-34
Intracompany SPP Related Fees	($125,735,155)	Schedule H/WP H-2-38
Wind Power Expense	($886,310)	Schedule H/WP H-2-44
Underground Vault Expense	$455,873	Schedule H/WP H-2-50

The PUD has reviewed and verified these amounts and has no adjustment to the Company's requested adjustments in those areas.

The PUD recommends that the Commission:

- Eliminate the SPP Transmission System Additions ("STSA") rider;
- Eliminate the Renewable Transmission System Additions ("RTSA") rider, with the SPP Transmission Revenue ("SPPTR") and Transmission Service Revenue Credits ("TSRC") components credited through the SPP Cost Tracker ("SPPCT") and the New Renewable Energy Credits ("NREC") and Green Power Wind Rider Revenue ("GPWRR") components credited through the Fuel Adjustment Clause ("FAC");
- Approve Phase 1 of OG&E's proposed Underground Vault and Manhole Maintenance Program, with OG&E to provide yearly updates on progress and expenses incurred in Phase 1 for the next three years and with Phase 1 to remain in place until this Commission determines, following a review, in OG&E's next general rate case proceeding whether the Company should proceed with Phase 2 or discontinue the program;
- Approve inclusion of Air Quality Control Systems ("AQCS") consumable costs in the FAC, conditioned on this Commission approving any one of OG&E's Environmental Compliance projects; and
- Approve modification to the SPPCT tariff for interim review.

PUD believes these proposals are fair and reasonable to both the Company and its customers and are in the public interest.

Kiran Patel

Kiran Patel is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission"). Ms. Patel filed responsive testimony on March 21, 2016. The purpose of her testimony was to provide detail of areas assigned to her that were reviewed by PUD and to discuss the review process. In addition, her testimony supported her areas of review relative to the Oklahoma Gas and Electric Company ("OG&E" or "Company") application for an order adjusting its rates, changes, and terms and conditions of service in the State of Oklahoma.

Ms. Patel reviewed the following areas: rate case expenses, regulatory expenses, gas in storage, bad debt expense, power generation utility, consumable cost removal, taxes other than income taxes, O&M generation non-fuel expense, large invoices, information-instructional/miscellaneous-sales expense, renewable energy certificate ("REC") revenues, unbilled revenues over/under, fuels and/or purchased power expenses, and outside service.

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

Current Rate Case expense: OG&E proposed an estimated total rate case expense amount of $1,160,000, to be amortized at $580,000 per year over two years. PUD proposed PUD Adjustment No. H-1, of $324,961 annually. After the adjustment, PUD allows recovery of the annualized adjustment amount of $255,039.

Regulatory expenses: OG&E proposed a projected total amount of $1,274,921 (the 2014 total amount of $108,699 and 2015 total amount of $1,166,222) to be a normalized level of $528,762. PUD recommends an adjustment that would allow $142,679 of OG&E's requested normalized amount of $528,762. When amortized over two years, this would allow recovery of $71,339 annually for regulatory expense over two years.

Gas in Storage: OG&E proposed to decrease 1,149,456 MMBtu natural gas inventory for the total amount of $3,086,959. OG&E made an adjustment to its gas-in-storage expense to phase out its "cushion" gas inventory. PUD recommends an adjustment increase of 3,756,393 MMBtu, to the level of gas in storage inventory and will make PUD Adjustment No. B-4, for the total amount of $857,885 to increase the gas-in-storage level to 3,756,393 MMBtu.

Bad Debt expense: OG&E proposed to increase operating expense for bad debt by $72,914. PUD made PUD Adjustment No. H-4, to decrease bad debt operating expense by $27,418.

Power Generation Utility: OG&E proposed an adjustment to increase the water cost associated with operation of the Redbud Power Plant. PUD agrees with OG&E's proposed adjustment; therefore, PUD did not make an adjustment.

Consumable Cost Removal: OG&E proposed to remove $268,995 of environmental consumable costs incurred during the test year. PUD agreed with the Company's proposed adjustment.

Taxes other than Income Tax: PUD did not recommend an adjustment to miscellaneous taxes. PUD reviewed OG&E work paper W/P-H-18 concerning taxes other than income tax and the Company's support documentation.

O&M Generation Non-Fuel expense: After reviewing OG&E's account that included the cost of labor, materials, and expenses incurred in production of steam for electric generation, PUD has not proposed any adjustment for O&M Generation non-fuel expense.

Large Invoices: The Company provided a list of large invoices, meaning greater than $250,000, for the test year. The amount of large invoices in this Cause totaled $2,330,549,697. After review of invoices provided, PUD recommends no adjustments.

Informational-Instructional-Miscellaneous-Sales expense: PUD reviewed the Company's exhibit, accounts and data for the test year and six-month post-test year period related to activities that encouraged safe, efficient, environmentally protective and economical use of utility service and assistance to customers. OG&E did not propose an adjustment and also PUD recommends no adjustment.

Renewable Energy Certificate ("REC") revenue: OG&E proposed an adjustment to remove revenues booked as a result of REC sales from various wind resources to the wholesale market during the test year. PUD agreed with the OG&E's adjustment.

Unbilled Revenues Over/Under Recovery: OG&E proposed an adjustment to remove unbilled revenue and associated kWh, resulting in a $3,400,000 reduction in revenues and a reduction of 54,269,600 kWh. PUD does not propose any adjustment to the Company's recommendation for Unbilled Revenues Over/Under Recovery.

Fuels and/or Purchased Power expenses: OG&E proposed an adjustment to remove all fuel and purchased power costs from the test year, excluding cogeneration capacity payments. OG&E proposed to remove from the test year all fuel expenses, including costs passed to customers through the Fuel Adjustment Clause, but excluding capacity payments. PUD recommends no adjustment to the fuel and/or Purchased Power expenses.

Outside Services: OG&E did not propose any adjustment to this subject area, which includes certain professional and legal services. As a result of communication between PUD and the Company, PUD determined that some expenses were incorrectly included in this account. Consequently, PUD Adjustment No. H-14 was made to decrease the Outside service costs in the amount of $200,000.

Kathy Champion – Responsive Testimony

Kathy Champion is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. In Cause No. PUD 201500273, Ms. Champion on March 21, 2016, filed responsive testimony regarding advertising expenses of Oklahoma Gas and Electric Company ("OG&E" or "Company")

included in Company Accounts 907-916 and adjustments included in OG&E work paper W/P H-2-40.

Ms. Champion reviewed all information and testimony provided by the Company in this Cause related to advertising expenses included in Accounts 907-916. Ms. Champion also reviewed Commission orders, testimony related to areas in prior causes, and work papers provided by OG&E. Ms. Champion reviewed 17 O.S. §180.1 regarding Advertising Expenses by Public Utilities, and Commission electric utility rules at OAC 165:35-7-1 regarding promotional policies and practices and at OAC 165:35-41 regarding Demand Programs. Ms. Champion also reviewed information gathered through on-site visits and in response to data requests, including invoices, allocation of expenses, newspaper inserts, pamphlets, and photographs of events that the Company considered educational advertising.

Ms. Champion recommended disallowing OG&E's request for recovery from ratepayers of costs for customer education efforts, related to energy efficiency, variable peak pricing and demand side management, in the amount of $537,115. Ms. Champion recommended this disallowance because cost recovery for customer education through a Demand Program Rider ("DPR") related to those programs was already granted previously by Commission Order No. 605737 approving a settlement in Cause No. PUD 201200134. Ms. Champion testified that approving recovery of additional funds for education in this Cause may[23]:

1) Be contrary to the settlement and the total recovery authorized by Order No. 605737,
2) Dilute the reported impact on customers,
3) Circumvent the rules related to the cap on recovery of costs related to the Demand Programs, and,
4) Misrepresent the overall cost effectiveness of the Demand Programs.

Ms. Champion testified that she believes this proposal is fair, just, and reasonable to both the Company and its ratepayers.

Kathy Champion – Rate Design

In Cause No. PUD 201500273, Ms. Champion on March 31, 2016, filed responsive testimony regarding areas of rate design and other miscellaneous issues raised by the Application of OG&E. She specifically addressed the Company's proposed changes in rate design for residential and small commercial customers, the use of riders, the proposed Pay-as-you-go or "PayGo" billing option, OG&E's proposed smart meter opt-out option, the proposed Distributed Generation ("DG") tariff, and proposed changes to the Company's miscellaneous charges.

Ms. Champion reviewed all information and testimony provided by the Company in this Cause related to rate design and additional miscellaneous areas. Ms. Champion also reviewed Commission orders, testimony related to areas in prior causes, and work papers provided by OG&E. Ms. Champion communicated with the Company regarding its rate design proposals

[23] Champion Responsive Testimony, Cause No. PUD 201500273, Page 6, Lines 10 through 17.

through email, phone calls, in-person reviews, electronic information/data requests and reviewed responses to these requests.

Ms. Champion recommended the Commission approve the following:

1. PayGo option, with language added to the terms and conditions of service to further clarify and define participation terms as discussed in her responsive testimony;

2. Smart meter opt-out fees proposed by the Company for this option;

3. Elimination or continuation of Riders – Ms. Champion agrees with Company's recommendation to eliminate the System Hardening, SmartGrid, Security, Crossroads, SPP Transmission System Additions, and the Renewable Transmission System Additions Riders. Ms. Champion also agrees with the Company's proposed continuation of the separate Demand Program, Storm Cost Recovery, and the SPP Cost Tracker riders;

4. Miscellaneous fees – Ms. Champion recommends modification to the Service Initiation Fee, Reconnect and the Meter Test Fee as described in her responsive testimony[24];

5. DG tariffs – For this class of customers with distributed generation, Ms. Champion recommends use of the Time-of-Use ("TOU") tariff, not to include the demand charge proposed by the Company. Also recommends that the Company conduct a cost-effectiveness review of the DG customer resources to determine the benefit that such resources provide to OG&E's system through the estimated life of those resources;

6. Limited rate design changes, with moderate increases in the customer charges for residential and commercial classes and elimination of the shoulder season months for the residential or "R-1" class;

7. Development of a demand charge pilot program for residential and commercial customers to permit the Company to evaluate customer acceptance, understanding and performance of demand charges.

Ms. Champion testified that she believes these proposals are fair, just, and reasonable to both the Company and its ratepayers.

Jeremy K. Schwartz

Jeremy Schwartz is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst. Responsive testimony of Mr. Schwartz, as a PUD witness regarding the cost of service ("COS") by

[24] Champion Rate Design Responsive Testimony, Cause No. PUD 201500273, Pages 31 through 32

Oklahoma Gas and Electric Company ("OG&E"), was filed on March 31, 2016, in Cause No. PUD 201500273.

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 OG&E. 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 recommended that OG&E perform an updated Minimum Intercept study before proposing any change to the base service charge of any class of customers in future causes that it files before this Commission.

Mr. Schwartz stated that based on results of PUD's inputs to OG&E's COS study, retail customers would be allocated a cost increase of $6,108,242.

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

- The Company is to conduct a Minimum Intercept study to identify and allocate customer-related costs for distribution assets before proposing a change to the base service charge for any customer class in any future cause before this Commission; and,
- The revenue distribution described in his testimony.

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

Sharhonda Dodoo

Sharhonda Dodoo is a Public Utility Regulatory Auditor in the Public Utility Division ("PUD") of the Oklahoma Corporation Commission. On March 21, 2016, she filed Responsive Testimony in Cause No. PUD 201500273, the Application of Oklahoma Gas and Electric Company ("OG&E" or "Company") for authorization to modify its rates, charges, and tariffs for retail electric service in Oklahoma. The purpose of Ms. Dodoo's testimony was to address the expense areas of Dues and Donations, Legislative Advocacy, and Administrative Expenses.

After reviewing the Application, testimony of Company witnesses and associated work papers, Ms. Dodoo did not propose any adjustments in the areas of Legislative Advocacy and Administrative Expenses.

Ms. Dodoo proposed one PUD adjustment to disallow recovery from ratepayers of $115,673.50 of the $1,275,765.00 that the Company requested recovery from ratepayers for OG&E's payments for Dues, Donations, and Memberships. While OG&E asserts that such payments and activities help to support its efforts to build good relationships in the communities that it serves as an electric utility, PUD believes that some of these costs result in benefits to both ratepayers and stockholders and, therefore, these expenses should be shared between those two

groups. Ms. Dodoo believes that PUD's recommended adjustment is fair, reasonable, and in the interest of ratepayers and the Company.

Robert C. Thompson

Robert C. Thompson is employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "Commission"). Mr. Thompson filed responsive testimony on March 21, 2016. The purpose of his testimony was to provide detail of the areas that were reviewed by PUD and to discuss the review process for Oklahoma Gas & Electric Company ("OG&E" or "Company") Cause No. PUD 201500273. In addition, his testimony supports his proposed adjustments in his areas of review in this Cause and the Accounting Exhibit relative to the OG&E application for an order adjusting its rates, charges, and terms and conditions of service in the State of Oklahoma.

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

- Robert Thompson covered the PUD accounting exhibit and overall accounting adjustments,
- David Garrett covered the Depreciation and Cost of Capital,
- Jeremy Schwartz covered Cost of Service,
- Kathy Champion covered Rate Design and General Discussion on Riders,
- Jason Chaplin covered SPP Transmission Cost and related matters,
- Geoffrey Rush covered Payroll Expenses and Director's Salary and Expenses,
- Hunter Hogan covered Rate Base and related expenses,
- Kiran Patel covered Rate Base and related expenses,
- Shar Dodoo covered legislative advocacy.

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

After conducting a thorough review of OG&E's Application package and conducting an on-site audit, Mr. Thompson proposes adjustments as shown below:

Plant in Service: PUD proposes adjustments to update plant in service to the 6-month post-test year balance at December 31, 2015. PUD's Adjustment B-3 increases plant in service included in rate base by $14,157,440.

Accumulated Depreciation: PUD proposes an adjustment to update accumulated depreciation to the 6-month post-test year balance at December 31, 2015. PUD's Adjustment B-4 decreases accumulated depreciation by $32,037,383, which would result in an increase to rate base.

Cash Working Capital: PUD proposes an adjustment to the cash working capital (CWC), which includes all of PUD's proposed changes to those accounts included within the cash working capital calculation. PUD agrees with the cash working capital methodology which excludes non-cash items such as depreciation, investment tax credit and common equity. PUD's adjustment will decrease cash working capital included in rate base by $1,104,128.

Accumulated Deferred Income Tax: PUD proposes no adjustment to update accumulated deferred income tax to the 6-month post-test year balance at December 31, 2015.

Prepaid Pension Asset: PUD supports the inclusion of $54,974,401 in prepaid pension assets in rate base as proposed by OG&E.

Amortization Expense: PUD agrees to the proposed amortization expense to include amortization on the legacy meters included in the Company's filing of $6,742,797.

Production Tax Credits: PUD proposes to continue the inclusion of production tax credits in base rates instead of in a rider as proposed by the Company.

Incentive Compensation: It is PUD's opinion that all of the Company's short-term incentive compensation and 25 percent of long-term incentive should be included in the Company's revenue requirement.

Interest Synchronization: PUD proposes an adjustment to the interest expense within the income tax calculation to reflect changes to the rate of return and rate base. Interest synchronization is a method that provides an interest expense deduction, for regulatory income tax purposes, equal to the ratepayers' contribution to OG&E for interest expense coverage. PUD's proposed adjustment for interest synchronization would decrease the net income before income tax by $1,734,039.

Current Tax Expense: PUD is proposing an adjustment to current income taxes to reflect PUD's adjustments to the operating income statement, including the revenue deficiency, resulting in a net decrease to OG&E's operating income of $54,519,937.

Hunter Hogan

Mr. Hunter Hogan is employed by the Public utility Division ("PUD") of the Oklahoma Corporation Commission and filed Responsive Testimony on March 22, 2016, in Cause No. PUD 201500273. The purpose of Mr. Hogan's testimony is to present PUD's recommendation for his assigned areas in response to the Application filed by Oklahoma Gas and Electric Company ("OG&E" or "Company").

Mr. Hogan recommended five (5) adjustments in the areas of materials and supplies, fuel inventories, prepayments, customer deposits and customer advances for construction ("CAC"), and interest on customer deposits.

For other areas that Mr. Hogan reviewed, he did not recommend any adjustments. Those areas included Company policy on refunding customer deposits, tax collections payable and deferred credits balances, miscellaneous deferred debits balances, operating reserves and accrued liabilities, consolidated companies and subsidiaries balance sheet, income statements for the test year and previous year, cost allocation basis, affiliate or subsidiary general data, affiliate or subsidiary contracts, assets sold or transferred to affiliates or subsidiaries, services or products received from affiliates/subsidiaries, services or products provided to affiliates or subsidiaries, and reestablished special contracts.

Overall, Mr. Hogan recommended the following PUD adjustments:

- Adjustment No. 3 in the amount of $872,170, to decrease the Materials and Supplies account;
- Adjustment No. 5, in the amount of $19,673,909, to increase the Fuel Inventories account;
- Adjustment No. 8, in the amount of $87,331, to increase the Prepayments account;
- Adjustment No. 6, in the amount of $1,246,132, to increase the Customer Deposits and CAC account; and
- Adjustment No. 13, in the amount of $18,205, to increase the Interest on Customer Deposits account.

Steve W. Chriss

I am Steve W. Chriss, Senior Manager, Energy Regulatory Analysis, for Wal-Mart Stores, Inc. I filed responsive testimony and exhibits in this case on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively "Wal-Mart").

Wal-Mart currently has 54 stores, a distribution center and related facilities that take electric service from OG&E, primarily under the Power and Light Time-of-Use, Service Level 5 ("PL TOU SL5") tariff. Electricity is a significant operating cost for retailers; increases in the cost of electricity to retailers can put pressure on consumer prices and on other expenses required by a business to operate.

Customer Impact

In considering the Company's request, I urge the Commission to also thoroughly and carefully consider the impact of that request on OG&E's customers. Any increase in the Company's rates should be only the minimum amount necessary to provide adequate and reliable service, while also providing an opportunity to earn a reasonable return.

Production Cost Allocation

Wal-Mart advocates that electric rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, send proper price signals, and minimize price distortions. A critical part of developing cost-based electric rates is the allocation of a utility's fixed generation assets among the various customer classes.

The timing and size of a utility's production plant capacity additions are made to meet the maximum demand placed on the utility's system by all customer classes. This maximum demand is also known as its coincident peak ("CP"). Allocating production capacity costs on the basis of a utility's system, CP ensures that the resulting rates reflect cost causation and minimize cost responsibility shifts between rate classes. In contrast, allocating fixed production capacity costs on a variable or energy basis can introduce shifts in cost responsibility from lower load factor classes to higher load factor classes.

The Company proposes to allocate its production capacity costs using an Average and Excess ("A&E") allocator based on OG&E's four summer coincident peaks ("4CP"). Based on my analysis, I find OG&E's use of the A&E allocator to be reasonable. An A&E allocator appropriately recognizes the contribution of each class to average demand, as well as the relative peak demand of each class.

My analysis of OG&E's monthly peaks for the test year indicates that an appropriate CP-based production cost allocator should use 2CPs instead of 4CPs, as the CPs for July and August are significantly higher than the CPs for the remaining months. However, the June and September CPs are within 20 percent of the overall CP demand, and are significantly higher than the remaining the CPs for the remaining months. The inclusion of these two months would also match the Company's summer season and align production cost allocation with the Company's rates.

On balance, Wal-Mart does not oppose OG&E's proposed A&E 4CP production capacity cost allocator.

Revenue Allocation

The Company's cost of service study ("COSS") reflects a wide discrepancy between current class revenue requirement levels and the revenue requirement levels needed for each class to recover its respective cost of service at OG&E's requested rate increase. This discrepancy is clearly shown by the relative rate of returns ("RRORs") shown in the COSS for the various classes. RRORs compare the rate of return for an individual rate class to the total system rate of return.

An RROR greater than 100 percent means that a particular rate class is paying rates in excess of the costs incurred to serve that class, while an RROR less than 100 percent means that the class is paying rates less than the costs incurred to serve that class. OG&E's COSS shows that under present rates, PL TOU SL5 has an RROR of 115.3 percent. This means OG&E is recovering more revenue from the class than it costs the Company to serve that class.

The Company proposes to allocate its requested revenue increase in a manner consistent with its COSS results, though the proposal would not move the revenue requirement for each class to its cost of service level. At the Company's proposed revenue requirement, Wal-Mart does not oppose the Company's proposed revenue allocation.

If the Commission determines that the appropriate level of revenue requirement is less than that proposed by the Company, however, I recommend that the Commission begin the

revenue allocation process with the Company's proposed allocation, and use the reduction in revenue requirement to bring the revenue requirement for each class closer to its respective cost of service level.

PL TOU Rate Design

The Company proposes to change the balance of the charges within the PL TOU SL5 by reducing the on-peak energy and demand charges, and by increasing the off-peak energy and winter energy charges. However, OG&E's proposed changes to the PL TOU SL5 rate design do not reflect the rate's underlying cost of service according to OG&E's COSS. My review of OG&E's PL TOU SL5 unit cost shows that the current demand charge only collects 41 percent of what a cost-based demand charge would collect, and yet the Company proposes to reduce the demand charge further in this cause. Additionally, all of the PL TOU SL5 energy charges are significantly higher than the cost-based non-fuel energy charge.

In addition to this lack of cost justification for the proposed demand and energy rates, I have two other concerns with the Company's proposed PL TOU SL5 rate design. First, OG&E's proposal to shift distribution demand costs from $/kW demand charges to $/kWh energy charges also shifts demand cost responsibility from lower load factor customers to higher load factor customers, who utilize the Company's facilities more efficiently. This results in a misallocation of cost responsibility as higher load factor customers overpay for the demand-related costs incurred by the Company to serve them, and are essentially penalized for using the Company's system more efficiently.

My second concern is that the Company's proposed PL TOU SL5 rate design would operate counter to the price response purpose of the rate by lowering the on-peak energy charge and decreasing the differential between the on-peak and off-peak charges. This proposed change dilutes the peak price signal and can discourage load shifting as compared to the current energy charge structure.

A more effective rate design for PL TOU SL5 would be to maintain or increase the differential between the on-peak and off-peak charges. This would maintain the existing incentive for customers to shift energy for customers to shift energy consumption to the off-peak hours. In fact, OG&E is proposing exactly this type of rate design for the LPL TOU SL5 class, but without an explanation for treating PL TOU SL5 customers differently from LPL TOU SL5 customers.

On the basis of my analysis and for the purposes of this docket, at the Company's proposed revenue requirement, I recommend that the Commission reject OG&E's proposed PL TOU SL5 rate design. Instead, I recommend that the Commission:

1) Approve the customer charge as proposed by the Company for PL TOU SL5;
2) Maintain the current summer on-peak energy charge of $0.095/kWh, summer off-peak energy charge of $0.012/kWh, and winter energy charge of $0.012/kWh; and

3) Apply the PL TOU SL5 revenue requirement increase to the demand charge.

These changes will allow the PL TOU SL5 rate design to better reflect OG&E's cost of service and preserve the price signals that incent customers to respond to price signals and shift load to off-peak hours.

Oral Testimony

My prefiled responsive testimony may be supplemented by oral rebuttal and/or oral surrebuttal testimony at the evidentiary hearing in this matter, consistent with the procedural order issued in this docket.

Mark E. Garrett – Revenue Requirement

Mark E. Garrett is the President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation and consulting services. Mr. Garrett 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 testified in these proceedings on behalf of Oklahoma Industrial Energy Consumers ("OIEC") and Oklahoma Energy Results, LLC ("OER"), collectively "OIEC/OER." OIEC is an association, consisting of a diverse group of large consumers of energy in Oklahoma, which is involved in regulatory and legislative matters primarily involving natural gas and electric power. OER is an entity comprised of large industrial and independent power production members. Mr. Garrett's March 21, 2016, responsive testimony addresses various revenue requirement issues. In total, his responsive testimony recommendations result in a rate decrease of $32.6 million, as outlined below:

OG&E'S Proposed Rate Increase	**$ 92,494,692**
Adjust Plant Investment to 6-Month Level	$ 1,440,487
Adjust Accumulated Depreciation to 6-Month Level	3,330,536
Adjust Plant Held for Future Use	(124,633)
Adjust ADFIT to 6-Month Level	84,794
Adjust Customer Deposits to 6-Month Level	(132,667)
Adjust ARO to 6-Month Level	(403,104)
Adjust Materials and Supplies to 6-Month Level	(92,320)
Adjust Prepayments to 6-Month Level	9,175
Adjust Gain on Sale (Acct 254) to 6-Month Level	(109,051)
Adjust Net Pension Asset Balance to 6-Month Level	(744,562)
Apply OIEC/OER Cost of Capital Adjustments	$ (45,476,468)
Adjust Customer Growth to 6-Month Cutoff	$ (5,375,062)
Recognize Gain on Sale of Utility Assets	(591,808)
Reverse OG&E Payroll Adjustment	(5,097,319)
Adjust Payroll Taxes for Proposed Payroll Adjustments	(357,881)
Remove 50% of Annual Incentive Plan	(7,104,554)
Remove 50% of Payroll Tax on Annual Incentive Plan	(498,740)
Remove 100% of Executive Incentive Plan	(5,505,652)
Remove Supplemental Executive Retirement Plan	(1,713,195)
Reverse Adjustment for Affiliate Expense Allocation	(5,579,128)
Reverse OG&E Estimated Ad Valorem Adjustment	(4,166,889)
Limit Vegetation Management to 5-year Spending Level	(5,983,404)
Amortize Stranded Smart-Grid Meters over 15 Years	$ (3,679,140)
Adjust Expense for OIEC/OER Depreciation Rates	(37,298,897)
OIEC/OER Proposed Rate Decrease	**$ (32,674,789)**

Rate Base Updated to 6-Month Post Test Year Balances

Mr. Garrett testifies that, 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 updated the following rate base balances to December 31, 2015:

Plant in Service
Accumulated Depreciation
Plant Held for Future Use
Accumulated Deferred Income Tax
Customer Deposits
Accumulated Retirement Obligations
Materials and Supplies
Prepayments
Gain on Sale of Utility Assets
Net Pension Benefit Obligation Asset

The revenue requirement impacts for each account are shown in the summary above. Mr. Garrett did not update the Coal Supply Inventory or the Gas Supply Inventory accounts because the requested levels for these accounts was based on a calculated supply level. Thus, these accounts do not need to be updated to their actual 6-month post-test year levels.

Operating Revenue Adjustments

Mr. Garrett testified that overall revenue levels must be updated to the 6-month post-test year cut-off date. When investment levels (rate base) and expense levels are adjusted for known and measurable changes, revenue levels must also be adjusted to correctly synchronize the three major components for the revenue requirement formula. This adjustment increases revenues by $5,375,062 and reduces OG&E's requested rate increase by the same amount.

Mr. Garrett also explained how OG&E sold a rotor from the McClain plant to General Electric last year and recorded the gain from that sale to Account 254 in December of 2015. He explained that the widely-accepted treatment of gains from the sales of utility property is to refund those gains to ratepayers over some prescribed period of time determined by the Commission. He recommended that the balance in Account 254 be included in rate base and amortized into rates over a 2-year period. OG&E also recognized a gain on the sale of distribution facilities to the Choctaw Nation on June 30, 2015 in the amount of $119,654. Mr. Garrett explained that this gain should also be included in rates. He testified that the entire amount of this gain should be recognized in one year (rather than a 2-year amortization) because it appears to be representative of a normal level of gains recognized by OG&E over the last several years. The impact of this recommendation is shown in the summary above.

Operating Expense Adjustments

Payroll Expense: Mr. Garrett testified that OG&E's proposed payroll adjustment annualizes payroll expense at test year end by multiplying the final two-week pay period in June 2015 by 26 and then adds another 3% approximately for pay raises that will be awarded in 2016. Mr. Garrett testified that a payroll annualization that multiplies a final pay period by 12 or 26 is only appropriate if the final pay period is representative of ongoing levels. Here, it was not. Also, additional increases for the nominal amount of a pay raise are almost never appropriate because payroll levels do not increase by the nominal amount of a pay raise. Mr. Garrett testified that too many other factors impact payroll levels such as normal employee turnover, workforce reorganizations, capitalization ratios and productivity gains. Moreover, these pay raises were beyond the 6-month adjustment window.

Mr. Garrett testified that he compared actual payroll expense levels during the 6-month post-test year period with test year expense levels. At OG&E, 2015 payroll expense was only $91,247 higher than test year expense. At the Holding Company, though, 2015 payroll expense allocated to OG&E was $377,670 lower than test year expense. Thus, total payroll expenses actually decreased by $286,423 during the 6-month period after test year-end. This means that the test year level is a reasonable level for setting rates.

Mr. Garrett also testified that a payroll annualization six months after test year-end would effectively be projecting payroll costs for the next 12-month period, which is getting well beyond the test year. Even if it were appropriate to project costs effectively 18 months beyond the test year, a simple payroll annualization, with nothing more, is inadequate. At a minimum, productivity gains would have to be incorporated into a payroll projection. According to the Bureau of Labor Statistics, productivity gains in the manufacturing sector have averaged about 2.1% from 2007 - 2015. This means that any projected payroll cost increases from an annualization at December 31, 2015, would have to be offset with a 2.1% reduction for productivity, which would effectively eliminate any projected payroll increase.

Annual Incentive Compensation Plan: Mr. Garrett proposes to reduce the requested level of annual incentive expense by 50% to eliminate the portion of the incentive plans related to financial performance measures. From his review of the plans, more than 50% of the plan costs are tied to financial performance. This adjustment is consistent with the Commission's prior treatment of the issue. In PSO's last two litigated rate cases, the Commission reduced PSO's requested annual incentive compensation by 50% based upon the extent to which the plans were tied to financial performance. In OG&E's last litigated rate case, the Commission disallowed 60% of the annual incentive plan costs.

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

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

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

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

A breakdown of OG&E's annual incentive plan was provided in the Company's response to AG 3-5 Supplement. This breakdown shows that 38.38% of the payout is related to customer satisfaction measures and 61.62% is related to financial performance measures.

Mr. Garrett testified that the argument that incentives should be included in rates because the amount is reasonable when compared with the amounts paid by other utilities misses the point. The question for regulators is not whether the amount paid for incentives is reasonable, but whether the incentives themselves are necessary for the provision of service. 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. Also, as stated above, because incentive pay related to financial performance is generally disallowed, most of the utilities that OG&E competes with for talent generally do not recover all of their incentive compensation in rates. Therefore, OG&E is not put at a competitive disadvantage when its incentive pay is similarly adjusted. The adjustments arising from removal of 50% of the annual plan expense and applicable payroll taxes are $7,104,554 and $498,740 respectively.

Long-term Incentive Plan: Mr. Garrett testified that the Company is proposing to include $5,977,907 in rates for its long-term stock-based incentive plans for officers, directors and selected senior management of the Company. Stock-based compensation to officers, executives and key employees is excluded as a general rule. Since officers of any corporation have a duty of loyalty to the corporation itself and not to the customers of the company, these individuals typically put the interests of the company first. Undoubtedly, the interests of the company and the interests of the customer are not always the same, and at times, can be quite divergent. Further, long-term executive incentive plans are specifically designed to tie executive compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. Since the compensation of the employee is tied over a long period of time to the company's stock price, it 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.

The results of the Garrett Group Incentive Survey, discussed in the previous section of this testimony, show that most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that long-term, stock-based incentives are excluded in virtually every state.

Mr. Garrett testified that 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 incentive payments made during the test year in Cause Nos.: PUD 91-1190; PUD 04-610; PUD 2006-285; and PUD 2008-144.

Generally, utilities argue that executive incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. The problem with the "total compensation package" argument is that when utilities, such as OG&E, compete with other utilities for qualified executives, and the executive incentive compensation plans of those other utilities are not being recovered through rates, these utilities (delete OG&E) are not placed at a

competitive disadvantage when its executive incentive compensation is excluded as well. The adjustment needed to remove 100% of the long-term stock incentives is $5,977,907.

Non-Qualified Supplemental Employee Retirement Plan ("SERP"): OG&E provides supplemental retirement plan benefits to certain highly-compensated individuals at the Company. These supplemental retirement plans are provided because benefits under the general retirement plans are subject to limitations under the Internal Revenue Code ("Code"). Benefits payable under these supplemental plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $260,000 for 2014 and $265,000 for 2015. In the test year, the Company paid $1,860,147 for non-qualified plans.

Mr. Garrett recommended that SERP costs be disallowed as a matter of principle. If SERP costs are disallowed, ratepayers still pay for all of the executive benefits on the first $265,000 and shareholders pay for the executive benefits on salary levels above $265,000. 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. Further, because officers of any corporation have a duty of loyalty to the corporation, these individuals are required to put the interest of the company first. This creates a situation where not every cost associated with executive compensation should be presumed to be a cost appropriately passed on to ratepayers. Many regulators exclude executive bonuses, incentive compensation and supplemental benefits, understanding that these costs should be borne by shareholders. The Oklahoma Commission disallowed 100% of PSO's SERP expense in Cause No. PUD 200600285 and again in Cause No. PUD 200800144. 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.

Ad Valorem Tax Expense: The Company is proposing to increase test year ad valorem tax expense by the average percentage increase experienced in this account over the past 3-year period. The Company's approach is not an appropriate method for quantifying a *known and measurable change* to ad valorem tax. Since ad valorem tax expense each year is the result of extensive negotiations with the Oklahoma Tax Commission regarding the valuation of OG&E's taxable property, the amount cannot be estimated based on average annual increases in the expense level over the past several years. In other words, there is no relationship between the amount of ad valorem tax paid in the past and the amount of tax expense that will be assessed during the rate-effective period. The expense increase for the rate-effective period, if any, cannot be predicted as proposed by the Company. Since the Company's proposed adjustment for ad valorem tax expense is based on a flawed methodology, Mr. Garrett recommends the Commission reject the Company's adjustment to increase test year expense by $4,166,889.

Vegetation Management Cost Increase: OG&E is proposing significant increases for both distribution and transmission vegetation management costs. OG&E is proposing an increase of $11,518,525 for distribution costs and an increase of $1,692,500 for transmission costs. This

represents an 81% increase for distribution and a 60% increase for transmission. OG&E provides no support at all for the transmission increase. It merely asserts that there has been a 15% increase in line-miles since 2010, which in no way explains a 60% cost increase over test year levels. For the distribution increase, OG&E points to the expiration of the System Hardening Rider. The System Hardening Rider provided OG&E with additional vegetation management costs from 2010 through 2014 – on top of what OG&E collected in base rates – to help OG&E "catch up" to its 4-year cycle requirements. OG&E asserts that going forward, it needs a level of costs similar to the level provided through the system hardening rider to once again help it "catch up" with its 4-year cycle requirements.

Over the past several years as the system hardening rider revenues declined, OG&E failed to increase the amount it was spending out of base rates to keep up with the 4-year cycle program. While system hardening expenditures were declining from 2010 through 2014, OG&E's base rate expenditures were not increasing. This fact is very important in light of OG&E's response to AG Data Request 7-18, where OG&E made the following important admission:

With the expiration of system hardening, OG&E no longer has the resources to maintain all lines the same and moved to a 2-tier cycle program which categorized circuits in two ways: Circuits with high customer density and/or a high priority for restoration are categorized as category 1 and are maintained end-to-end including preventive brush control and pole clearing. Category 2 circuits are inspected on cycle and only vegetation interfering with reliability is addressed. . . . It is OG&E's intent to eliminate the 2-tier cycle and clear all circuits the same.

This response actually includes three important admissions: (1) that OG&E chose not to replace the declining system hardening revenues with additional OG&E expenditures out of base rates; (2) that OG&E changed its cycle program to a 2-tierred approach that did not adequately clear the second-tier lines; and (3) that OG&E now wants to return to a program that clears all lines equally. To return to a program that clears all lines the same, OG&E asserts that it will have to, once again, spend additional funds to "catch up" the second-tier lines that were inadequately cleared under its elective 2-tier program.

Mr. Garrett testified that OG&E is obligated to adequately maintain its system. It cannot simply choose to forego making necessary maintenance expenditures to improve its bottom line. In other words, OG&E cannot choose to forego necessary maintenance expenditures in order to send more money to the shareholders – and then ask ratepayers to help "catch up" the foregone maintenance costs. At this point, OG&E should quantify the "catch up" amount – that is, the amount OG&E determines it should have spent over the last several years to maintain an adequate vegetation management program, rather than the 2-tierred approach that did not adequately clear second-tier lines. OG&E should then pay this "catch-up" amount out of the Company's retained earnings to promptly clear the second-tier lines that were not adequately cleared. In Mr. Garrett's opinion, the Commission should hold OG&E accountable for failing to make the necessary expenditures required to adequately maintain its vegetation management program over the past several years by setting the vegetation management expense at the 5-year average spending level.

Corporate Cost Allocation Increase: OG&E is proposing to increase rates by $6,057,685 for costs the Holding Company will no longer be able to allocate to Enable Midstream Partners starting in 2016. These costs include costs for central functions such as Accounting, Human Resources and Information Technology. These costs are OGE Holding Company costs that are now being allocated to both OG&E and Enable. Beginning in 2016, OGE Energy Corporation will no longer be allocating these costs to Enable. So, going forward, it plans to allocate all of the costs to OG&E instead. This adjustment is inappropriate for several reasons. First, the cost allocation change is outside the test year and outside the 6-month post-test year period. OGE Energy Corporation's cost-sharing agreement with Enable ends in January 2016, which is beyond the 6-month post-test year cutoff date. Title 17 Sec. 284 requires that the Commission give effect to known and measurable changes that occur during the 6-month period after test year. According to the statute, the *change* must occur *during* the 6-month period. This change occurs beyond the 6-month period. Second, for recovery in rates, costs must be both necessary and reasonable – necessary for the provision of service and reasonable in amount. The costs that OGE Energy Corporation wants to allocate to OG&E in 2016 may be necessary for the holding company, but the amount is not a reasonable amount for OG&E. The reasonable amount for OG&E is the amount that OG&E was paying for these costs when Enable was picking up its share of the costs. Now that Enable is no longer obligated to pay its share of these costs, OGE Energy Corporation cannot simply slough off the excess costs onto OG&E and expect ratepayers to pay the higher levels. Mr. Garrett proposed to reverse OG&E's adjustment that increases rates for costs the parent company will no longer be able to allocate to Enable Midstream Partners starting in January 2016. The adjustment reduces *pro forma* operating expense by $5,579,128.

Depreciation Expense

OIEC/OER witness Mr. Jacob Pous proposed numerous changes to the Company's depreciation study resulting in new proposed depreciation rates for many of the Company's plant accounts. Mr. Garrett applied these recommended depreciation rates to OG&E's plant balances at December 31, 2015, the 6-month cut off in this case. The impact of this adjustment is $37,298,897.

Stranded Smart-Meter Costs

Pursuant to the Stipulation reached among the parties in Cause No. PUD 201000029, OG&E accumulated costs associated with the stranded meters and the Smart Grid Web Portal in a regulatory asset account. The test year balance for both items is $34,329,676 and $6,127,104, respectively. OG&E now seeks to include these costs in rate base and recover the costs from ratepayers through a 6-year amortization in the amounts $5,721,613 for stranded meters and $1,021,184 for the web portal. The six-year amortization was an agreed-to provision in the Stipulation approved in Cause No. PUD 201000029, and that provision was part of an overall Stipulation that included OG&E's agreement to file a rate case in 2013. The amortization provision contemplated an amortization of costs beginning with issuance of a 2013 OG&E rate case order. OG&E failed to file a 2013 rate case as required by the Stipulation and later refused to file the case even when requested by Staff to do so. As a consequence, OG&E's failure to file a 2013 rate case should result in the Company's forfeiture of any benefits that would have been derived from its promised 2013 rate case. One of these benefits would have been the six-year

amortization of stranded costs resulting from the Smart Grid roll-out. Mr. Garrett proposed that the stranded costs be amortized over the 15-year life of the new smart meters. This is the approach taken by PSO for its stranded meter costs and Mr. Garrett testified it is the correct amortization period absent an agreement by the parties to a shorter period. This recommendation results in an adjustment of $3,679,140.

Recommendations of Other OIEC/OER Witnesses

Mr. Garrett also quantified the revenue requirement impacts of the other OIEC/OER witnesses' recommendations. Mr. Parcell addressed the cost of capital issues. Specifically, he recommended a Return on Equity ("ROE") of 9.0%. The impact of his recommended ROE is a reduction of $(45,476,468). Mr. Pous proposed new depreciation rates for several OG&E plant accounts. His recommendations resulted in a decrease in Oklahoma depreciation expense of $(37,298,897).

Rebuttal Testimony of Mr. Garrett

Mr. Garrett testified that Staff witness R. Thompson's recommendation to include 100% of short-term incentive expense and 25% of long-term expense is a significant departure from the Commission's long-standing policy of excluding 50% of short-term incentive costs and 100% of long-term costs. Mr. Garrett testified that Staff provided virtually no rationale to support this significant departure from prior Commission orders. In his opinion, such a significant departure requires sufficient explanation and support. However, Staff provided no rationale whatsoever for including 25% of the long-term, stock-based incentives for upper management, and very little rationale for including 100% of the short-term incentives. In fact, the rationale Staff did provide for including the short-term incentives was actually incorrect. At page 27, lines 9-13, of Mr. Thompson's Responsive Testimony, he states that "The Company's short-term incentive plan is not driven by profits of the company but is driven by other goals set for individual employees and should be included." This statement is not accurate. An analysis of the Company's short-term plan was provided by the Company in its response to AG 3-5. This analysis shows 61.62% of the plan payments were directly tied to financial performance in the test year. Staff's recommendation also ignores the Commission's decisions in numerous litigated rate cases over the past 25-year period. The Commission has consistently excluded all of the long-term incentives and at least half of the short-term incentives. These cases included PUD 910001190, PUD 200400610, PUD 200500151, PUD 200600285, and PUD 200800144.

Mr. Garrett also testified that Staff failed to recognize a known and measurable change in OG&E's revenue levels during the 6-month period after test year-end. In his opinion, this is an important omission that must be corrected. In his responsive testimony, Mr. Garrett explained that a 6-month revenue update is necessary to fully comply with the requirements of Title 17 § 284 to recognize known and measurable changes that occur within six months of test year end. When material changes in the investment levels and the expense levels are recognized, material changes in revenue levels must also be recognized. OG&E provided the incremental growth after test year-end through December 31, 2015. OG&E quantified the increase as $5,375,062.

Mr. Garrett also testified that OIEC/OER depreciation expert, Mr. Jack Pous, only addressed the depreciation rates for transmission, generation and general assets. He did not address the depreciation rates for OG&E's distribution assets. As a result, the Commission will need to add Staff's distribution depreciation rate impacts to OIEC/OER's revenue requirement recommendations to obtain a complete picture of the overall rate decrease that could be ordered in this case. Staff witness D. Garrett provides a comprehensive analysis of OG&E's plant balances including distribution asset plant balances in his responsive testimony. Staff's distribution depreciation rate adjustments added to OIEC/OER's revenue requirement recommendations adds another $15,183,126 to OIEC/OER's recommended rate decrease making the overall rate decrease $(47,858,126).

Mark E. Garrett – Cost of Service/Rate Design Issues

Mr. Garrett's cost of service and rate design responsive testimony recommendations are summarized as follows:

1. The purpose of a cost of service study is to allocate a utility's costs among its customer classes. The costs that each class causes on the utility's system are compared with the revenues collected from that class. When the revenues collected from each class fully cover the costs caused by that class, rates are said to be set at ***cost-of-service.***

2. When rates are not set at cost-of-service, some customers are paying costs that are caused by other customers. Over-payments and under-payments among the classes are referred to as inter-class subsidies.

3. Rates set at cost-of-service among all customers are preferable for many reasons. They are more equitable because customers pay the actual costs incurred to serve them. They are more efficient because they send better price signals to customers who can adjust their usage accordingly.

4. Although OG&E has improved its allocation methodology in this application, its rates still are not cost-based.

5. Inter-class subsidies promote the inefficient use of electricity, which ultimately results in economic waste, overall higher energy prices, reduced productivity and lower employment levels. The Commission should work to eliminate price subsidies to the greatest extent possible.

6. State regulatory commissions widely recognize the importance of cost-based rates, however, they often find it difficult to eliminate existing subsidies when large rate increases are required. As such, the best time to eliminate an inter-class subsidy and to implement cost-based rates is when a rate ***decrease*** is warranted, as is the case here.

7. OIEC and OER have recommended an approximate $32 million rate decrease. The Attorney General has recommended an approximate $10 million decrease.

Based on these recommendations, the Commission has an opportunity to lower the overall revenue requirement and to correct the inter-class subsidy. In my testimony, I explain the reasons this is the right time to eliminate the subsidy and align all customer classes at cost-of-service rates.

8. I have provided analysis on the impact of implementing cost-of-service rates at various levels of rate decreases that the Commission may adopt, including an allocation based on a zero-increase level.

9. In this testimony I also discuss the Company's proposed treatment of its Production Tax Credits ("PTCs"). PTCs are federal tax credits allowed for qualified renewable energy projects. In the test year, OG&E's PTCs were $40,492,979. These credits lower the Company's taxes, and thereby reduce the revenue requirement. However, the Company has proposed to flow the PTCs through the Fuel Adjustment Clause ("FAC"), rather than including the tax credits in base rates. I disagree with the Company's proposed use of the FAC in this manner.

10. The FAC is created by statute to recover fuel and purchased power costs. The Commission should not allow the use of the FAC for anything other than its intended purpose. Rider-recovery was not statutorily authorized for PTC credits, nor should it be. PTC-related cost fluctuations are not large enough to jeopardize the financial integrity of the utility. The Company has not articulated any legitimate reason the FAC should be changed now to include PTC credits.

11. OG&E is also requesting a modification to the FAC to allow recovery of certain commodities (limestone, powder activated carbon, and ammonia) used for emissions-reduction technology. The Company asserts that these costs are variable and correlated to the amount of fuel consumed, and should be recovered through the FAC. I disagree. AQCS costs are not volatile in nature, nor large enough to jeopardize the financial integrity of the utility. The Company has not articulated any legitimate reason the FAC should be changed to include AQCS costs. I recommend the Commission deny rider treatment for these costs.

12. OG&E is requesting regulatory asset treatment for the future environmental upgrades at two of its Seminole generating units that have completion dates far beyond the test year and the 6-month post-test year period for allowed adjustments. These upgrades include the Activated Carbon Injection ("ACI") system and the Low NOx burners that will be placed in service in 2016 and 2017, respectively. I testify that regulatory asset treatment is not appropriate for these costs.

13. Regulatory asset treatment is a cost-tracker mechanism in which costs between rate cases are either recovered directly through a rider, or deferred through a regulatory asset and recovered in a subsequent proceeding. In effect, cost-tracker treatment encompasses both riders and deferred accounting (regulatory asset) mechanisms.

14. Regulatory commissions traditionally approve cost-trackers only under "extraordinary circumstances." Commissions consider cost trackers and riders an exception to the general rule for cost recovery, and place the burden on a utility to demonstrate why certain costs require special treatment.

15. OG&E's environmental compliance costs presented in this cause do not meet the criteria for regulatory asset treatment. The circumstances typically required for approval of cost-trackers arise for costs that are:

(1) Largely outside the control of the utility;
(2) Unpredictable and volatile;
(3) Substantial and recurring; *and*
(4) Causing severe financial consequences to the company.

At best, OG&E's environmental compliance costs meet one of the four criteria, that is, the costs are EPA-driven and out of the Company's control, at least to some extent. This is not a sufficient reason for the Commission to approve regulatory asset treatment. OG&E's environmental compliance costs are not unpredictable or volatile; they are non-recurring; and they are not so significant as to cause severe financial harm to the Company. OG&E has made no showing that special circumstances exist to justify tracker mechanism for these environmental costs. For these reasons, I recommend the Commission deny regulatory asset treatment for these costs.

Mr. Garrett also made the following recommendations in his rebuttal testimony:

1. OG&E's cost of service study shows (and the parties all agree) that the Large Power and Light ("LPL") class and the Oil and Gas Production ("OGP") class are heavily subsidizing the other classes. Thus, the primary rate design issue that needs to be addressed is the elimination of the inter-class subsidies. Yet, Staff and AG's recommendations merely reduce the subsidy but do not eliminate it. The LPL and OGP classes are the two classes least able in the current economic downturn to subsidize other ratepayers. These classes include customers in industries that make up the state's largest job producers. They also include many customers from industries that compete on a global rather than local level. Mr. Garrett explained in his Rate Design Testimony that every dollar that industrial companies pay for electricity above the actual cost of that electricity is a dollar not available to provide jobs and economic growth in Oklahoma. For this reason, the Commission should work to eliminate interclass price subsidies to the greatest extent possible. In his opinion, Staff and AG's recommendations to marginally reduce the subsidy do not go nearly far enough.

2. Mr. Garrett also testified that the Oklahoma Hospital Association ("OHA") is recommending a special rider to eliminate the subsidy that its members are paying in rates. OHA provides little to no justification for this recommendation and no explanation of exactly who will pick up the difference. OHA certainly does not explain why its members who compete on a local and regional level should receive rate relief while the oil and gas producers and manufacturing industries that compete on a global level should not. For the sake of economic development, job creation and job retention,

OHA members, oil and gas producers and the manufacturing industries on OG&E's system all need to have the subsidies they provide to other customers eliminated. The Commission should not favor one industry at the expense of others when all industries need appropriate rate relief.

David C. Parcell

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

I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have previously filed cost of capital testimony in over 525 public utility ratemaking proceedings before some 50 regulatory agencies in the United States and Canada. Much of this testimony has been on behalf of commission staffs. Attachment 1 provides a more complete description of my education and relevant work experience.

I have been retained by the Oklahoma Industrial Energy Consumers ("OIEC") and Oklahoma Energy Results, LLC ("OER") to evaluate the cost of capital aspects of the current rate filing of Oklahoma Gas and Electric Company ("OG&E"). I have performed independent studies and am making recommendations on the current cost of capital for OG&E. In addition, since OG&E is a subsidiary of OGE Energy Corp. ("OGE" or "Parent"), I have also evaluated OGE in my analyses.

My overall cost of capital recommendations for OG&E are shown on Schedule 1 of Exhibit DCP-1 and can be summarized as follows:

	Percent	Cost	Return
Long-Term Debt	46.69%	5.62%	2.62%
Common Equity	53.31%	9.00%	4.80%
Total	100.00%		7.42%

This proceeding is concerned with OG&E's regulated electric utility operations in Oklahoma. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. I have used the actual capital structure of OG&E, as proposed in the Company's filing in my analyses, however, I recommend that in future cases OG&E's common equity ratio be reduced to a lower, more appropriate level, relative to other electric utilities.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the cost rate for long-term debt (5.62 percent) of OG&E.

The third step in the cost of capital calculation is the estimation of the cost of common equity ("ROE"). I have employed three recognized methodologies to estimate the ROE for

OG&E. Each of these methodologies is applied to a group of proxy utilities similar to OG&E/OGE and the group of electric utilities used by OG&E witness Robert B. Hevert. These three methodologies and my findings are:

Methodology		Mid-Point
Discounted Cash Flow (DCF)		8.85%
Capital Asset Pricing Model (CAPM)		6.85%
Comparable Earnings (CE)		9.50%

My DCF analyses utilized the dividend yields for the three-month period December 2015 to February 2016. Five sources of potential dividend growth were considered. My broad-based DCF results were in a range of 7.2 percent to 9.4 percent. My recommendation focused on the upper portion of this range, or 8.3 percent to 9.4 percent, with a mid-point of 8.85 percent.

My CAPM analysis utilized the yields on 20-year U.S. Treasury bonds, the actual betas of each proxy company and three measures of the market risk premium. My CAPM results were in a range of 6.7 percent to 7.0 percent, or 6.85 percent mid-point. I did not give significant weight to my CAPM results.

My CE analysis looked at historic (2002-2015) and projected (2016-2020) ROEs and related M/Bs for the proxy groups as well as the S&P 500 group. I found that both historic and projected ROEs for the utility groups were in a range of 9.1 percent to 10.4 percent, with the preponderance of the ROE being in the range of 9.1 percent to 10.0 percent. Related M/Bs were well over 100 percent. My CE conclusion was 9.0 percent to 10.0 percent.

My recommendation for OG&E focuses on the results of the DCF and CE analyses. I have focused on the 8.85 percent to 9.50 percent results for the DCF and CE analysis. My 9.0 percent point recommendation, which is in the lower portion of my range, reflects the following factors:

- OG&E's excessive common equity ratio;
- OG&E's substantial array of riders and other favorable regulatory mechanisms;
- OG&E recovers 43 percent of its revenues through Commission approved riders (which transfer risk from shareholders to ratepayers and mitigate regulatory lag); and,
- The continuing level of lower interest rates.

Combining these three steps into weighted cost of capital results in an overall rate of return of 7.42 percent (which incorporates a ROE of 9.00 percent).

My testimony also commented on the cost of capital testimony of OG&E witness Robert B. Hevert. I showed that his analyses significantly overstate the cost of equity for OG&E. In addition, 24 of his 29 cost of equity measures are below the 10.25 percent ROE he recommends.

Mr. Hevert's constant growth DCF analyses overstate the ROE for OG&E due to his exclusive reliance on analysts' estimates of EPS growth, and only the most optimistic measures of EPS growth. His multi-stage DCF also focuses exclusively on EPS forecasts for the short-term growth rate, while his long-term growth rate is excessive and substantially exceeds other estimates made by federal government agencies.

Mr. Hevert's CAPM analyses overstate the ROE. First he uses, as the risk-free rate, projected yields on U.S. Treasury bonds, rather than actual yields, which is the proper risk-free rate. In addition, Mr. Hevert's risk premium also overstates the proper risk premium since it is based upon his excessive DCF results for the S&P 500 which also focus only on EPS growth forecasts.

Mr. Hevert's risk premium analysis likewise overstates the ROE for OG&E. It is based upon the same deficient methodologies he employed in his DCF and CAPM analyses.

Finally, Mr. Hevert cites four "additional factors" that he claims should be considered in setting OG&E's ROE. Each of these claimed factors has, in his view, an upward impact on the ROE. I demonstrate that each of these "factors" are already reflected in OG&E's security ratings. It is noteworthy that OG&E's ratings were raised by both Moody's and S&P in 2014, notwithstanding any effect of these "factors."

Jacob Pous

Mr. Pous addresses the Company's proposed changes to depreciation rates as reflected in a new study performed by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") and sponsored by Mr. John Spanos. The new depreciation study is based on plant as of the end of December 2014 ("2014 Study"). The 2014 Study reflects an overall increase in depreciation expense of $29,639,005 based on plant as of June 30, 2015, or approximately a 10% increase over test year depreciation expense.[25] Based on independent review of the development of depreciation parameters for major accounts, it is necessary to recommend many adjustments to the proposed new depreciation rates and corresponding expense. Due in part to the extensive problems throughout the 2014 Study and other factors, not all appropriate adjustments are being recommended.[26] A brief summary of the various adjustments Mr. Pous recommends relating to depreciation and/or amortization expense are presented below.

- **Production Plant Net Salvage** – The Company proposes terminal and interim negative net salvage total values exceeding $317 million for its steam and other production generating facilities. The amount is based extensively on the undefined and unsubstantiated "judgment" of Mr. Spanos. In particular, Mr. Spanos provides nothing of value to support his estimated $225 million of terminal net salvage costs to dismantle or decommission each generating site

[25] OG&E W/P H-2-21 line 72.

[26] Some of the other major problems in the 2014 Study are the calculation of remaining life that differs from the industry standard, the calculation methodology used for interim retirements, and the process establishing the level of interim net salvage. Given all the potential issues in the 2014 Study, it was determined that correction of all potential problems might best be accomplished over a few depreciation studies, and that focus should be limited to the issues addressed herein for this case. In addition, Mr. Pous' engagement excluded the review of distribution depreciation proposals.

subsequent to the projected retirement of a generating unit. As discussed in Mr. Pous' testimony, there is no basis to accept or adopt any portion of the terminal net salvage request. Denial of the Company's unsupported claim for terminal net salvage results in a $19.9 million reduction to depreciation expense based on plant as of December 31, 2014.[27]

- **Wind Farm Life Span** – The Company proposes an artificially short 25-year life span for its investment in wind farms. Mr. Spanos relies on his judgment, which in turn relies on a claim that some undefined and unsubstantiated discussion with Company personnel is an adequate basis for adopting his proposal. The Company and Mr. Spanos have provided nothing of substance in support of its request. Alternatively, the overall investment in a wind farm can realistically exceed 30 years. Therefore, reliance on a 30-year life span, a life span that Mr. Spanos has previously recommended for this type of investment, is a more realistic life span estimate and is within Mr. Spanos' judgmental range. Adjusting the Company's proposed life span from 25 to 30 years results in a reduction in annual depreciation expense of $6.5 million based on plant as of December 31, 2014.

- **Holding Company Depreciation** – The Company incorporates, but remains silent on the basis and support for, a $10 million annual accrual for its Holding Company's depreciation expense. Based on independent analyses, it appears the Company is relying on the composite results of Mr. Spanos' 2009 Holding Company Depreciation Study ("2009 HC Study"), which was reflected in the settlement of OG&E's last case (Cause No. PUD 201100087). The largest component of the investment in the Holding Company is in various software systems. The life reflected in the 2009 HC Study for software systems is only half as long as Mr. Spanos now is assigning to the software systems recorded at the electric portion of the Company. Recognizing a first step towards a more realistic life for major investments in software systems results in a $4.3 million reduction to the annual depreciation expense based on plant as of December 2014, and $5.2 million as of December 2015.

- **Utility Electric Company Amortization of Software** – While Mr. Spanos recommends extending the 3-year amortization of investment in software to 10 years, he fails to properly capture the ongoing impact of the existing 3-year amortization. The 3-year amortization will be in place until the Commission adopts a final order for rates to change sometime past the middle of 2016. That means that the Company's $29 million software investment in 2012 will be fully accrued before rates in this case go into effect. Therefore, Mr. Spanos' theoretical calculation that incorrectly assumes that the proposed 10-year amortization is applicable as of the end of 2014, if adopted, would result in double recovery of the majority of the investment reflected in his amortization calculation. Proper recognition of the fact that the 3-year amortization will remain in place at least through the middle of 2016 results in a $3.1 million reduction in revenue requirement.

- **Mass Property Life Analysis** – The Company relies on an actuarial analysis approach for estimating average service life ("ASL") and corresponding mortality dispersion pattern for mass property accounts. Mr. Spanos' interpretation of the actuarial results is inappropriate and leads to artificially short ASLs for numerous accounts. Relying on more appropriate

[27] OG&E's calculation understates the impact due to reliance on an unusual rounding approach.

interpretation of actuarial results, information relating to unusual historical events, and other information results in a $6.7 million reduction in annual depreciation expense based on plant as of December 31, 2014.

- **Mass Property Net Salvage** – The Company's proposals for several mass property accounts result in excessive levels of negative net salvage. The Company's proposal fails to take into account specific impacts reflected in historical data that are not indicative of future net salvage expectations. Corrections of this and other problems results in a $5.6 million reduction to annual depreciation expense based on plant as of December 31, 2014.

- **Combined Impact** – The combined impact of the various adjustments noted above are not simply the summation of each individual standalone adjustment. Certain adjustments are interactive. The combined impact of the various above noted issues results in a $45.1 million reduction in the proposed annual depreciation expense based on plant as of December 31, 2014, as set forth on Exhibit (JP-1) through (JP-3).[28] The test year impact of my recommendations is a reduction of $47,018,778 for plant as of December 31, 2015, and will be reflected in the revenue requirement testimony submitted by OIEC witness Mr. Garrett.

James W. Daniel

Responsive Testimony (March 21, 2016)

James W. Daniel, Vice President of the firm GDS Associates, Inc. ("GDS") and Manager of GDS's office in Austin, Texas, testified on behalf of the Oklahoma Attorney General ("AG"). Mr. Daniel's Responsive Testimony regarding Oklahoma Gas and Electric Company's ("OG&E's") proposed revenue requirement was to address the Company's proposed rate treatment of production tax credits ("PTCs") and air quality control systems ("AQCS") consumables, and the Company's proposed regulatory asset for future environmental compliance project ("ECP") costs. The recommendations Mr. Daniel makes in his testimony include:

(1) OG&E's proposal to flow PTCs through the Fuel Adjustment Clause ("FAC") should be rejected. Instead, PTCs should continue to be used to reduce the base rate revenue requirement. As Mr. Daniel noted, Oklahoma Statutes define the FAC as any mechanism which allows a public utility or electric generating cooperative to automatically adjust its charges above or below the base amount included in its rates, based upon changes in costs of fuel for generation of electricity, purchased power, or purchased gas. *See* 17 O.S. § 250(5). Automatic rate adjustment clauses, such as the PTCs, are typically reserved for the recovery of major expenses that are volatile. OG&E has not provided any support for its claims that PTCs are highly variable and are used as a credit to federal and state income taxes, which are a large and stable component of OG&E's revenue requirement. As a result, Mr. Daniel asserts that costs (and credits) flowed through the FAC should be limited to fuel and energy-related purchased power expenses, as has been the past practice of this Commission.

[28] The impact of the electric system software adjustment is based on activity through mid 2016.

(2) The Commission should reject OG&E's proposal to recover the costs of consumables used in its Air Quality Control System ("AQCS") through the FAC. He noted that the Commission previously denied OG&E's requested recovery of AQCS costs through the FAC in Cause No. PUD 201400229. Automatic rate adjustment clauses, such as the FAC, are typically reserved for the recovery of major expenses that are volatile, yet OG&E's witness (Rowlett) states that the Company's costs will be identical for 2016 and 2017. In addition, test-year expenses for consumables are quite low. As a result, Mr. Daniel recommends that these costs should continue to be recovered in OG&E's base rates.

(3) OG&E's proposal to create a regulatory asset for future ECP costs should be denied. The future environmental compliance costs that OG&E seeks to include in the regulatory asset are for facilities which are not expected to go into service until May 2016 and March 2017. If the Commission approves OG&E's requested recovery method, it would in effect eliminate or reduce the normal regulatory lag for new facilities. Mr. Daniel contends that there is no basis for treating the future ECP facilities any differently than other future facilities, since OG&E did not specifically seek pre-approval for cost recovery of these ECP costs under 17.O.S §286(B). Therefore, he contends that those costs should not be treated differently than any other capital additions that are placed in service between rate cases.

Responsive Testimony (March 31, 2016)

Mr. Daniel's Responsive Testimony filed March 31, 2016, addressed certain cost allocation and rate design issues with OG&E's proposed rate increase. His testimony discussed both policy reasons and OG&E-specific reasons that the Commission should or should not approve various elements of OG&E's proposed cost allocation and rate design. The issues Mr. Daniel addresses include:

(1) OG&E improperly classifies a substantial portion of its distribution plant related costs for conductors (both overhead and underground), poles and conduit as "customer-related." From a cost-causation standpoint, these distribution costs are incurred to meet customer demands and should be classified as demand-related costs.

(2) OG&E's proposed distribution of its requested revenue increase to the customer classes gradually moves customer class revenue levels towards each class's cost of service in order to temper customer impacts. Consistent with the rate setting principle of gradualism, Mr. Daniel agrees with OG&E's proposed revenue distribution objective, especially in light of OG&E's proposed restructure of the standard residential rates However, OG&E's proposed revenue distribution should be revised to reflect the impact of item (1) above. Mr. Daniel developed his recommended revenue distribution, which moves all classes towards their allocated cost of service, while also avoiding severe rate increases that would be caused by setting class revenues equal to each class's cost of service.

(3) Mr. Daniel asserts that OG&E's proposed residential monthly customer charge increase of over 100% is excessive and contrary to one of OG&E's witness's testimony (Ahmad

Faruqui). Mr. Daniel provides analysis which shows that the Company classified too much cost as customer-related; this is the primary cause of OG&E's substantial increases proposed for the monthly Residential and General Service customer charges. The proposed rise in the residential monthly customer service charge results in severe rate increases for many residential customers and should be rejected by the Commission. Mr. Daniel provided a revised Class Cost Of Service Study which supported a significantly lower and cost-based customer charge.

(4) Mr. Daniel provided analysis which showed that OG&E's proposal to restructure the standard residential rate design to include a demand charge substantially increases rates for some customers, while reducing rates for other customers. His analysis shows that rates for fewer than 1% of U.S. utilities contain residential customer demand charges, most of which are voluntary, as stated in OG&E witness Ahmad Faruqui's testimony. Mr. Daniel is not opposed to the adoption of a residential demand charge, citing the merits from a cost-causation standpoint. However, Mr. Daniel recommends that OG&E implement it gradually, due to the significantly disparate rate impacts among the residential customers, and to avoid violation of the rate principle of rate stability.

(5) OG&E's proposed new residential customer prepay billing option ("Pay Go"') should be revised per the recommendations of AG witness Ed Farrar.

(6) Finally, Mr. Daniel asserted that OG&E failed to consider customer bill impacts when designing its proposed rates. As a result, he recommended that the Commission reject OG&E's residential rate design, due to the substantial bill increases for numerous residential customers.

Errata Responsive Testimony and Exhibits (April 8, 2016)

On April 8, 2016, Mr. Daniel filed Errata Responsive Testimony and Exhibits ("Errata") for the purpose of amending his March 31, 2016 Cost Allocation and Rate Design Responsive Testimony ("Rate Design Responsive Testimony"), as well as his Exhibits JWD-7 and JWD-8, which Exhibits were attached to his Rate Design Responsive Testimony. In his Errata, Mr. Daniel replaced certain amounts and percentages that were inadvertently left unedited in his Rate Design Responsive Testimony and Exhibits. Mr. Daniel's Errata did not change his recommendations in his Rate Design Responsive Testimony, as summarized immediately above.

Kevin J. Mara

Responsive Testimony (March 21, 2016)

On March 21, 2016, Kevin J. Mara filed Responsive Testimony on behalf of the Oklahoma Attorney General ("AG"). Mr. Mara is a Principal with GDS Associates, Inc., an energy and utility consulting firm. The purpose of Mr. Mara's testimony was to present his findings and recommendations in this case with regard to: (1) review of the vegetation management budgets of Oklahoma Gas and Electric Company ("OG&E" or "Company") and (2) comment on OG&E's proposed vegetation management tracker. Mr. Mara has also filed testimony regarding cost of service in this Cause. In making his evaluation and resulting

conclusions and recommendations, Mr. Mara relied upon the information in the direct testimony of OG&E's witnesses, OG&E's responses to data requests ("DRs") submitted by the AG and other parties, analysis performed by GDS, and his educational training and related professional experience.

The Oklahoma Corporation Commission ("OCC" or "Commission") Rules, see Okla. Admin. Code §165:35-25-15, require utilities to perform vegetation management on a four-year cycle. OG&E has two categories of vegetation management: Category 1 circuits are to be cleared end-to-end on a four-year cycle, and Category 2 circuits are to be inspected for vegetation issues every four-years, and only immediate reliability concerns will be addressed at that time. The Category 1 feeders are circuits with high customer density and/or high priority for restoration, while Category 2 circuits are circuits with lower customer density. With the expiration of the System Hardening Budget, OG&E shifted from a one-tier system to a two-tier system, prior to 2014.

The data presented by OG&E shows that the Company has been unable to meet a four-year trim cycle for the past four years. Over the four-year period from 2012 to 2015, OG&E performed vegetation management on only 8,520 miles of distribution line, which is only 46% of the Company's total miles of distribution line in Oklahoma (18,587 miles).

In 2009, OG&E requested and obtained approval for the System Hardening Rider as a means for a one-time catch-up, so they could meet a four-year trim cycle in future years. According to OG&E's testimony, once the System Hardening Rider expired, OG&E discovered that the amount of funding in base rates is not adequate to maintain the four-year cycle requirement.

Mr. Mara testified that OG&E is proposing to move from the two-tier vegetation management system to a single-tier system, and to manage all of the Company's rights-of-way as Category 1 rights-of-way, resulting in an increase in the Distribution Cycle Trimming Costs. OG&E has provided no basis for the need to shift to a single-tier system.

Mr. Mara estimated the shift to a single-tier system will be at a cost of $7,902,766 per year for each of the next four years. Mr. Mara noted that there has been no discussion by OG&E witnesses regarding specific improvements in reliability that can be expected by the change, nor are any studies presented to justify an annual operation and maintenance ("O&M") cost of $9,087,125. Another point to consider is that best practices for vegetation management in the electric utility industry suggest that a rigid right-of-way maintenance program with fixed clearance requirements applied to all distribution lines is not cost effective for reliability and resiliency. As shown in Mr. Mara's Exhibits KJM-1 and KJM-2, the difference between OG&E's pro forma cost for distribution cycle trimming ($23,359,503) and Mr. Mara's proposed two-tier system cost ($19,005,331) is $4,354,171, which represents a significant reduction in the Company's O&M costs. Further, the system reliability should actually improve under Mr. Mara's two-tier trimming system, because his proposed budget for vegetation management will have OG&E maintaining a four-year cycle with the funding provided by the recommended adjustment.

A four-year trim cycle consisting of vegetation management activities on 4,646 miles per year will reduce the amount of non-cycle work required. Mr. Mara testified that he believes that the current increase in non-cycle work is directly related to OG&E not completing a four-year trim cycle. Many of OG&E's feeders have not been trimmed in more than 8 years, naturally resulting in an increase in non-cycle work.

Mr. Mara recommended:

1. OG&E adhere to the mandated four-year trim cycle.

2. OG&E maintain the two-tier trimming system recognizing the differences between urban and rural feeders, which have very different vegetation issues.

3. OG&E be required to file quarterly reports during each year to report the progress of the Company's Vegetation Management Plan.

4. Reducing OG&E's budget for Distribution Cycle Trim by $4,354,171.

5. Reducing OG&E's budget for the non-cycle work by $657,027.

6. Disallowing OG&E's proposed vegetation management tracker.

Responsive Testimony (March 31, 2016)

On March 31, 2016, Mr. Mara filed Responsive Testimony to support the allocation factors for distribution costs, as such costs relate to OG&E's cost of service. In conducting his evaluation and making his resulting conclusions and recommendations, Mr. Mara relied upon the information in the direct testimony of OG&E's witnesses, OG&E's responses to data requests ("DRs") submitted by the AG and other parties, analysis performed by GDS, and his educational training and related professional experience.

FERC has regulated accounting standards used by electric utilities that group functional system components into specific accounts. For distribution systems, the FERC accounts are as follows:

364 Poles, Towers, & Fixtures
365 Overhead Conductors
366 Underground Conductors
367 Underground Conduit
368 Line Transformers

OG&E allocates distribution costs partly based on customer-related costs, and partly based on demand-related costs. Mr. Mara disagreed with OG&E's methodology because distribution systems are sized based on peak demand, not on the number of customers served. Mr. Mara recommends that one hundred percent (100%) of FERC Accounts 364, 365, 366, 367, and 368 be allocated as demand-related costs. This recommendation is consistent with OG&E's

transmission and substation cost allocation methods, and is consistent with the method used in other jurisdictions.

E. Cary Cook

E. Cary Cook, Senior Project Manager of GDS Associates, Inc., an engineering and consulting firm, filed Responsive Testimony on March 21, 2016, on behalf of the Oklahoma Attorney General ("AG"). The purpose of Mr. Cook's testimony is to present the findings and recommendations of the AG in this case with regard to:

(1) Oklahoma Gas and Electric's ("OG&E") proposal to include a dismantlement component in its production function's depreciation rates and expense;
(2) OG&E's proposal to include a 25-year service life for its wind power generating facilities depreciation expense; and
(3) OG&E's proposal to include general plant-related holding company depreciation expense for Accounts 392 and 396, based upon a previously developed composite depreciation rate.

Mr. Cook developed his Responsive Testimony based upon depreciation information included in Mr. John Spanos's Direct Testimony filed on behalf of OG&E, OG&E's responses to data requests submitted by the AG and other parties, and Mr. Cook's professional experience in the utility industry.

Mr. Cook recommended that OG&E not be allowed to recover dismantlement expense in its production function depreciation rates. It is uncertain whether OG&E's generating facilities will in fact ever be dismantled. Moreover, Mr. Cook noted that OG&E proposed to recover a dismantlement component in its depreciation rates without performing a detailed analysis of the cost of dismantlement. OG&E relied upon industry-wide information instead of using OG&E-specific data. Mr. Cook recommended the use of a 30-year life span for OG&E's wind power facilities, compared to OG&E's proposal to use a 25-year life span to develop its wind power depreciation expense. Mr. Cook's determination was made based upon a review of wind power's most recent technology, and the trend in longer lives for wind power facilities. Mr. Cook also determined that OG&E should apply OG&E's own company depreciation rates for General Plant Accounts 392 and 396 to determine OG&E's holding company depreciation expense. OG&E applied a previously developed holding company composite general plant depreciation rate to develop individual Accounts 392 and 396 instead of performing a more current analysis to develop the individual accounts' depreciation rates.

Mr. Cook recommends:

1. The Commission should reject OG&E's proposal to include a dismantlement component in its production depreciation rates. It is uncertain whether OG&E's generating plants will be dismantled. Also, OG&E developed its dismantlement expense based upon industry-wide data instead of conducting an OG&E-specific analysis.

2. Wind power generating facilities' depreciation rates should be based upon a 30-year life span, rather than the 25-year life span used by OG&E. More recent technology shows that a 30-year life span is more reasonable.

3. Holding Company depreciation expense for Accounts 392 and 396 should be based upon current OG&E accounts' respective depreciation rates. Instead, OG&E determined its holding company depreciation expense for these accounts based upon a previously developed holding company overall general plant composite depreciation rate.

J. Bertram Solomon

J. Bertram Solomon, Executive Consultant of GDS Associates, Inc., an engineering and consulting firm, filed Responsive Testimony on March 21, 2016, on behalf of the Attorney General of Oklahoma. In his testimony, Mr. Solomon presents the results of his review and critical analysis of the rate of return on common equity ("ROE"), capital structure, and overall cost of capital testimony and exhibits of Oklahoma Gas and Electric Company ("OG&E" or "Company") witnesses Mr. Robert B. Hevert and Mr. Donald R. Rowlett. In addition, Mr. Solomon offers the results of his own independent cost of common equity analyses (Exhibit JBS-1), and provides a recommendation for the appropriate capital structure, ROE, and overall rate of return ("ROR") for use in establishing the rates of OG&E in this proceeding.

To provide recommendations in this Cause, Mr. Solomon reviewed and analyzed OG&E witnesses' testimony and exhibits, other publicly available OG&E information, and other economic and capital market data. He also conducted an independent discounted cash flow ("DCF") analysis using a national proxy group of Value Line electric utilities with S&P and Moody's credit ratings comparable to those of OG&E. Mr. Solomon concluded that the best estimate of OG&E's current cost of common equity capital based on its actual capital structure of 53.31% common equity and 46.69% long-term debt is 8.90%. However, in light of OG&E's prior commitment in Cause No. PUD 950000148 to maintain a balanced capital structure, Mr. Solomon recommends a capital structure of 50% common equity and 50% long-term debt with an ROE of 9.25% for use in setting OG&E's rates in this proceeding. Mr. Solomon's recommended 9.25% ROE reflects the greater financial risk associated with the balanced 50/50 equity/debt capital structure, and will produce similar overall rate impacts as would the 8.90% ROE with OG&E's actual capital structure.29 Mr. Solomon noted that in recommending this 9.25% ROE, he considered the following factors: the current economic and capital market environment; the results of Mr. Solomon's quantitative analyses; his evaluation and corrections to OG&E witness Hevert's quantitative analyses; the environmental compliance and other concerns raised by Mr. Hevert; the reviews by Mr. Solomon and OG&E witness Rowlett, respectively, of state commission-allowed ROEs and capital structures; and the potential effect of regulatory lag.

With respect to the Company's capital structure, Mr. Solomon found that the 50/50 balanced capital structure falls well within the range of capital structures of the proxy groups of electric utilities used by both Mr. Solomon and Mr. Hevert, respectively, and well within the range of capital structures approved by state commissions during the 14 months since January 2015. As shown on Exhibit JBS-2, the range of common equity ratios approved by state commissions during the 14 months since January 2015 for electric utilities, other than in limited-

[29] While the 50/50 capital structure with a 9.25% ROE produces a higher weighted average after-tax overall rate of return of 7.44%, as compared to the 7.37% that would result from the actual capital structure and 8.90% ROE, the overall weighted average before-tax rates of return, which drive the related revenue requirement, are nearly the same at 10.36% and 10.37%, respectively. Both results assume the use of the Company's proposed 5.62% debt cost.

issue generation rider cases, was 28.5% to 56.0%, with an average of 48.0%. Thus, using the Company's proposed 5.62% cost of long-term debt and a balanced capital structure, Mr. Solomon recommends an overall weighted average cost of capital of 7.44%, rather than the 8.09% proposed by OG&E.

Mr. Solomon described the current economic and capital market conditions, including the slowly growing U. S. economy, the continuing low inflation rates that remain below the Federal Reserve's 2% target level, the strengthened value of the dollar, and continuing low interest rates and low cost of capital. He also noted that, even after the Federal Reserve's December 16, 2015, increase of 0.25% in its target for the short-term Federal Funds rate, utility stock prices have increased, resulting in lower utility stock dividend yields, and yields on long-term, 30-year Treasury bonds have declined.

Mr. Solomon determined that, while Mr. Hevert conducted numerous different empirical analyses, only one of them—the analysis applying the constant growth DCF methodology to a national proxy group of electric utilities—should be accorded any significant weight.30 Mr. Solomon noted that the average median and mean ROE results for Mr. Hevert's constant growth DCF analysis were 9.13% and 9.37%, respectively, which better support Mr. Solomon's recommended 9.25% ROE than Mr. Hevert's 10.25% ROE recommendation.

For his independent DCF analysis, Mr. Solomon selected a national electric utility proxy group using S&P and Moody's credit ratings, among other screening criteria. Mr. Solomon explained that his proxy group of 10 companies better reflects the risk characteristics of OG&E than Mr. Hevert's 19-company group; this is because Mr. Solomon required that proxy companies have credit ratings within one notch of OG&E's S&P rating, and within two notches of OG&E's Moody's rating.31 In contrast, Mr. Hevert only required that proxy companies have an investment grade credit rating, no matter how distant that rating might be from OG&E's rating. Restricting proxy companies to those with credit ratings closer to those assigned to OG&E provides an objective way to assure that the companies are seen by investors as comparable in risk to OG&E. This is because the credit ratings of S&P and Moody's are regularly reviewed by investors, and their rating evaluations are specifically designed to differentiate between risks of individual companies, and thoroughly consider a broad range of variables reflecting both the business risk and financial risk of the companies.

Mr. Solomon applied the two-stage DCF methodology endorsed by the Federal Energy Regulatory Commission, using his 10-company proxy group shown in Exhibit JBS-1 and dividend yield data for the 6 months ending February 2016. The results are a range of 6.77% to 9.64%, with a median of 8.37% and a mean of 8.45%. Based upon these DCF results for his proxy group and the aforementioned considerations, Mr. Solomon recommends that OG&E be

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[30] Mr. Hevert's other empirical analyses were a "multi-stage" DCF analysis wherein he forecasted dividends for each proxy company over the next fifteen years, and a stock sale price as of the end of that period; various capital asset pricing model ("CAPM") analyses; and various utility risk premium analyses. Mr. Solomon explained the practical difficulties in applying these other methods, some of the flaws in Mr. Hevert's application of those methods, and made some corrections to Mr. Hevert's analyses, the results of which better support Mr. Solomon's ROE recommendation than that of Mr. Hevert.

[31] Because there are no Value Line electric utilities within one notch of OG&E's Moody's credit rating, the criteria had to be expanded to include Value Line utilities within two notches of OG&E's Moody's rating.

allowed an ROE of 9.25% with a balanced capital structure of 50% common equity and 50% long-term debt.

Mr. Solomon recommends an ROE of 9.25% and an overall weighted average cost of capital of 7.44% for use in determining OG&E's rates in this proceeding.

Edwin C. Farrar

Responsive Testimony (March 21, 2016)

On March 21, 2016, Edwin C. Farrar pre-filed Responsive Testimony on behalf of the Attorney General of the State of Oklahoma ("AG"). He testified as to his educational and professional background as a Certified Public Accountant. He has testified previously before the Oklahoma Corporation Commission and his qualifications as an expert have been accepted. Mr. Farrar recommended certain adjustments to rate base and to the operating income statement of OG&E.

Mr. Farrar recommended that rate base be updated for known and measurable changes that occur within six months after the end of the test year, as required by statute, to December 31, 2015. Mr. Farrar recommended that payroll-related expenses be adjusted to levels at December 31, 2015; that the Commission adopt the adjustments it has made in previous rate cases to incentive compensation, which is of limited benefit to ratepayers; that the Commission exclude the cost of non-qualified pension plans from the revenue requirement; and that the Commission reject OG&E's adjustment to ad valorem tax expense.

Mr. Farrar testified that OG&E did not update rate base for known and measurable changes occurring within six months after the end of the test year as required by statute, because its Application was filed before that date. The Company only included some post-test year adjustments and estimates. Mr. Farrar's recommended adjustments to OG&E's filed exhibits to recognize its utility investments as of December 31, 2015, are as follows:

Plant in Service	$12,473,690
Accumulated Depreciation	$28,840,304
Prepayments	$79,453
Material, Supplies and Fuel Inventories	($799,431)
Asset Retirement Obligations	($3,490,626)
Customer Deposits and Advances	($1,148,809)
Net Pension Benefit Asset	($6,447,061)
Accumulated Deferred Income Taxes	$734,262
Net Change in Rate Base	$30,241,782

Mr. Farrar also recommended that Plant Held for Future Use be excluded from rate base, and that the gains from the sale of utility assets from the last rate case be included as a reduction to rate base. Plant Held for Future Use should be excluded from rate base because those assets are not used to serve current customers. The adjustment to exclude Plant Held for Future Use reduces the jurisdictional rate base by $1,079,239.

The gains from the sale of utility assets should be included as a reduction to rate base to keep the treatment of retired assets equitable. That is because assets that are no longer used to serve ratepayers are retired from service, which may include a cost to remove the asset from service, offset by sale or salvage proceeds. When an asset is retired before its anticipated useful life is complete, it would not be fully depreciated, and the sale may result in a net loss. A gain can result if the useful life is longer than was estimated when depreciation rates were set, or retirement costs are overestimated, or sale proceeds are underestimated. In the case of a net loss, the utility may use that net loss to reduce accumulated depreciation and increase future depreciation rates, or it may request a special recovery for the decommissioning of the asset. Both mechanisms serve to keep shareholders fully compensated for their investment. However, when a gain results from the sale of the asset and the gain is taken directly to shareholders instead of using it to offset the over-recovery of depreciation on the asset, the Company will receive a windfall anytime it overestimates depreciation expense. For that reason, Mr. Farrar recommended that the net gains that have been flowed directly to shareholders be used to reduce rate base, and be amortized over a reasonable period to offset the losses that are normally included in rate base and the related increase in depreciation or decommissioning expenses. The adjustment to include the gains from the sale of utility assets reduces the jurisdictional rate base by $1,136,352.

OG&E requested a regulatory asset for environmental upgrades to two of its Seminole generating units and for environmental consumables, if the Commission does not allow the recovery of those costs through OG&E's fuel adjustment clause. The environmental upgrade for Seminole Unit 1 is expected to be completed by May of 2016 and for Seminole Unit 3 by March of 2017. AG witness James W. Daniel recommended that the environmental consumables not be recovered through OG&E's fuel adjustment clause. Instead, Mr. Daniel recommended that the environmental consumables be recovered in base rates.

Mr. Farrar stated that under certain circumstances, the authorization for a utility to record a regulatory asset can be a sound regulatory policy. Those circumstances include when the cost is so high that it will impair the ability for a utility to earn its authorized return, when the amounts to be recovered are uncertain and the cost is not controllable by the utility, and when the cost is absolutely necessary for the operation of the utility. Mr. Farrar recommended that a regulatory asset not be allowed for the two environmental upgrades in this case because they will not be completed until after the end of the statutory update period, and because it is not possible to identify any increases in revenues or decreases in expenses that would offset the cost of these items.

If a regulatory asset is allowed, contrary to the AG's recommendation, the Commission should ensure that all issues impacting the utility's earnings are reviewed before recovery of the regulatory asset, and before any related deferred expenses are allowed in rates in a future rate case. At a minimum, the Commission should verify that the Company was not able to earn its authorized return during the period when costs were recorded for the regulatory asset. If the recording of a regulatory asset is not allowed, the Company may still earn its authorized return. For example, the Company's requested jurisdictional depreciation expense is $285 million per year. The Company's net plant investment will be reduced by that amount every year. That reduction offsets plant additions, which in the case of the Seminole environmental upgrades are much smaller, totaling only $42 million in the 21 months following the test year. While these

costs are significant in most contexts, in this case it is reasonable to assume that these costs can and will be offset by other cost reductions or increased revenue. Mr. Farrar recommended that the request for the regulatory assets be denied. However, if the Commission does approve the recording of a regulatory asset, he recommended that the recovery in a future rate case be conditional on an earnings review for the period in question, and that the recovery be disallowed if the Company is determined to have earned its authorized return.

Mr. Farrar recommended an adjustment based on OG&E's customer count updated to December 31, 2015, which he calculated using the Company's supplemental response to discovery response AG 2-10. This discovery response included OG&E's calculation of the impact of changes in customer levels for each rate class to December 31, 2015. This adjustment increases OG&E's pro forma jurisdictional electric revenue by $5,375,062 to reflect the changes in customer levels through December 31, 2015.

Mr. Farrar recommended several adjustments to operating expenses, including payroll, incentive compensation, non-qualified retirement plans, and gains realized on the sale of utility assets. OG&E had adjusted its payroll expense by annualizing the projected salaries of those employed by the Company on December 31, 2015, increasing the test year payroll expense by $5,650,503. It was not possible for OG&E to measure the actual payroll levels at December 31, 2015, because its application was filed on December 18, 2015. OG&E's proposed payroll expense is based on an estimate of the impact of future events instead of a measurement of the actual level of costs the Company experienced. Estimates are generally less accurate than actual measurements in determining the amount of an expense to include in rates.

Also, payroll should be annualized at December 31, 2015, which is six months after the end of the test year. If a later date is used, there will be bias in the rate-setting process to recognize increases in the revenue requirement, but not offsetting increases to sales and decreases to other expenses that might offset the increase in payroll costs. Mr. Farrar recommended using OG&E's annualized pay at December 31, 2015, to reflect actual payroll costs at the end of the six-month update period. Based on the Company's response to discovery request AG 2-11, OG&E's requested jurisdictional payroll cost should be reduced by $486,681, to reflect the annualized payroll cost at December 31, 2015, which is six months after the end of the test year. This adjustment impacts payroll taxes, which should be reduced by $34,165 to reflect the impact of the payroll adjustment.

OG&E offers its employees an annual or short-term incentive plan, as well as long-term incentive plans. The annual incentive plan covers all employees, while the long-term incentive plans only cover management level employees. This is similar to the annual incentive plans of other utilities, which typically include a mix of safety and operational goals, and the operational goals usually include company earnings. OG&E's long-term incentive plan is focused on earnings, which is also typical of other utilities. OG&E's annual incentive compensation plan indicates that it is heavily weighted to financial and operational objectives, with smaller components related to safety and customer satisfaction. From a regulatory perspective, the primary concerns of a public utility should be safety, reliability, customer satisfaction, and the cost of the utility's service. The latest J.D. Power and Associates survey of electric utilities ranked OG&E highest in residential customer satisfaction for midsize utilities in the south

region. However, OG&E ranked below average in business customer satisfaction. The Company awarded significant amounts of annual incentives for financial, operational and customer satisfaction goals, but employees failed to meet the minimum standards to receive the safety incentive award.

In the past the Commission has split the cost of annual incentive plans between the utility's shareholders and ratepayers. One-half of annual incentives have been included in rates. Mr. Farrar testified that it is appropriate to exclude some cost from rate recovery if those costs are not in the ratepayers' interest. For example, utilities are required to absorb the cost of lobbying activities and promotional advertising that may be against the public interest. Similarly, it would not be appropriate for ratepayers to bear the cost of financial incentives that may cause utility employees to seek rate increases. It has been said that a well-designed financial incentive should more than pay for itself with added revenue or cost savings, and if it doesn't, it should be discontinued. Apparently, financial incentive plans have been working for shareholders because utilities have maintained them, even though most utility commissions exclude the plans' expenses from utilities' revenue requirement, as has this Commission for OG&E. Mr. Farrar recommended that the Commission continue to exclude fifty percent (50%) of OG&E's annual incentive plan expenses from rates which reduces OG&E's jurisdictional pro forma expenses by $7,104,635, and reduces payroll tax expense by an additional $498,745.

Mr. Farrar testified that the Commission has excluded the cost of long-term incentive plans from utilities' revenue requirement, as most commissions do. That exclusion is because these plans are almost always entirely financial in nature, designed to increase utilities' earnings, regardless of how that is achieved. Mr. Farrar recommended that the Commission follow its policy to exclude the cost of the long-term incentive plans from rates. Incenting employees to pursue high earnings is not necessary for the provision of utility service and may even be detrimental to the interests of ratepayers. The adjustment to exclude the cost of the long-term incentive plans from rates reduces the jurisdictional revenue requirement by $5,505,684.

OG&E included the cost of non-qualified pension plans in the revenue requirement. A non-qualified pension plan covers the portion of the executives' retirement costs for salaries above the IRS limits, which are currently $265,000 per year. This means that fund contributions are not tax deductible, and as a result, companies rarely fund these plans. Mr. Farrar recommended that these costs be removed from the revenue requirement because this type of indirect compensation for highly paid executives is unnecessary and expensive. The adjustment to remove this cost reduces the Oklahoma retail revenue requirement by $1,713,195 for OG&E.

Mr. Farrar recommended that the net gains on the sale of utility assets be included as a reduction to rate base. Mr. Farrar recommended that the net gains be amortized before OG&E files its next rate case. The Company has proposed that its rate case expenses be amortized over two years, and Mr. Farrar recommended that same period be used to amortize the net gains on the sale of these assets. The Oklahoma retail jurisdictional amount of the adjustment to amortize the gains on the sale of utility assets over two years reduces pro forma expenses by $573,978.

OG&E based its requested level of ad valorem taxes on the average rate of the Company's tax increases over a three-year period, instead of matching the pro forma ad valorem taxes to pro forma levels of plant investment. OG&E requested that $74,607,317 in ad valorem taxes be included in the total Company revenue requirement. Mr. Farrar disagreed with the Company's method used to calculate the pro forma expense level. Mr. Farrar stated that an examination of the Company's costs for the calendar year 2015 shows that FERC Account 408.1, Taxes Other than Income Tax, increased by less than 0.24% over the test year. FERC Account 408.1 includes both payroll taxes and ad valorem taxes. The Company has proposed an increase to payroll tax expense of $392,720, which is greater than the test year to calendar year 2015 increase in the whole account of $215,432. The Company's adjustment clearly isn't justified. For that reason, Mr. Farrar recommended that the Company's adjustment be reversed. This adjustment reduces the jurisdictional ad valorem taxes by $4,166,889.

Responsive Rate Design Testimony (March 31, 2016)

Mr. Farrar pre-filed Responsive Rate Design Testimony on March 31, 2016. Mr. Farrar made certain recommendations with respect to OG&E's time of use programs, its proposal to implement demand charges, and its request to implement a prepaid electric service option, referred to as "PayGo."

OG&E has several time of use tariffs for its residential customers that were marketed under the name "SmartHours" in the Company's 2013-2015 demand portfolio. These optional tariffs have very high participation rates compared to similar programs offered by other utilities, and have resulted in a reduction in system peak demand and in total energy consumption. While OG&E no longer includes these tariffs as a part of its demand program, it has stated that it will continue to offer these tariffs to its customers. These time of use tariffs bring in less revenue for OG&E than the standard service tariff does. However, OG&E has not proposed in this case that it be able to recover its lost net revenue from these time of use tariffs. Mr. Farrar expressed his concern that with this loss of revenue as a result of the success of the time of use tariffs, OG&E will not be able to promote these tariffs to maintain the high participation rates in the future that they have previously attained. Mr. Farrar recommend that the Commission order OG&E to track the levels of customers participating in the SmartHours tariffs, and allow the Company to either recover the lost net revenues from increased participation, or to credit customers for reduced participation in these tariffs.

OG&E has proposed that demand charges be implemented for residential and small commercial customers. Mr. Farrar expressed the concern that implementation of a demand charge could undermine the effectiveness of OG&E's time of use tariffs, which are used to shift power consumption from peak periods to off-peak periods. This concern arises because OG&E is proposing that the demand levels for these time of use tariffs be measured at any time, and not just at the peak periods targeted by the Company's time of use rates.

OG&E's time of use rates offer customers an opportunity to save a significant amount on their electric bills by electing to obtain service under the Company's time of use tariffs. To obtain the greatest savings under these tariffs, customers need to reduce their electric service usage during weekday summer afternoons between 2:00 pm and 7:00 pm, a five-hour period.

Some customers shift their usage to off-peak periods to accomplish that objective. However, a customer who shifts his load to an off-peak period to save money under the SmartHours tariff could experience less savings under OG&E's proposed demand charge, which is based on usage measured during an off-peak period. While the demand charges are based on transmission and distribution costs, and the time of use rates are aimed to reduce production demand, the combination of the two charges can provide conflicting price signals to customers.

With regard to the demand charges proposed by OG&E, Mr. Farrar first recommended that a reduced tariff rate be implemented during this proceeding, as discussed by AG witness James W. Daniel. Second, he recommended that demand be measured only during peak usage periods during the summer months, when the time of use rates are applied for customers participating in those programs. Finally, Mr. Farrar recommended that OG&E monitor the impact of the demand charges on the participation levels in the Company's time of use tariffs, and provide annual reports on that impact to the Public Utility Division ("PUD") of the Commission and to the AG.

Mr. Farrar also testified as to OG&E's proposed prepaid service program, referred to as "PayGo." To implement PayGo, OG&E proposed amendments to Section 220 of its Terms and Conditions of Service Tariff (hereinafter "PayGo Tariff"). Pursuant to the PayGo Tariff, standard rates would apply, prorated to a daily basis when necessary. In the event of a $0 or negative balance, a customer would be disconnected, and would not receive a paper copy of a notice of disconnection at the customer's home. Some customers, including customers with medical necessities, would be prohibited from participating in PayGo.

Mr. Farrar discussed certain benefits of PayGo, which include that customers will be allowed to make as many payments as necessary throughout the month, will not face deposits or disconnect/reconnect fees, and will be able to pay off a portion of their arrears while maintaining electricity service. Further, Mr. Farrar discussed some of the reported benefits that prepaid electric service programs offer utilities, including fewer adversarial calls from customers, and reduction of consumer debt.

Mr. Farrar also discussed certain concerns of consumer advocates with programs like PayGo, including that the programs bypass traditional notice requirements for disconnection of service, such as by physical mail, or posting final notices at customers' households. Mr. Farrar reviewed a number of the Commission's rules with respect to disconnection of service. For example, ten days' written notice is typically required prior to disconnection for nonpayment of a bill (Okla. Admin. Code §165:35-21-20(b)). In addition, a utility must generally post written notice at a customer's home at least 24 hours prior to an impending disconnection (Id. §165:35-21-20(a)). Further, the rules either prohibit or delay disconnection when the outside temperature is freezing (Id. §165:35-21-10(c)(1)) or very hot (Id. §165:35-21-10(c)(2)); when a customer has applied for and is awaiting financial assistance from a government or social service agency (Id. §165:35-21-10(d)); when a customer requests a deferred payment agreement (Id. §165:35-21-10(e)); and when a resident in the customer's household is dependent on life-sustaining equipment, which equipment is electric (Id. §165:35-21-10(f)).

As a result of his review of OG&E's PayGo program, Mr. Farrar recommended that the Commission include the following provisions in its approval of PayGo:

(1) Customers should face no barriers if they wish to switch back to standard, post-pay service. Switching back to standard service should not require the customer to pay fees. If a customer still has arrears when switching back to standard service, or must pay a deposit, then OG&E should be required to offer a reasonable payment plan to assist the customer to transition back to standard, post-pay service.

(2) If a customer chooses to discontinue PayGo, OG&E should be required to refund any positive prepay balance to the customer (or to the energy assistance program, if applicable) within ten business days.

(3) As part of the enrollment process, OG&E should be required to obtain a customer's acknowledgement of the following statement:

> The continuation of your electric service under PayGo depends on you prepaying for service, and if your balance falls below $0, your service may be disconnected with notice by electronic means only. In the event of impending disconnection, no notice will be posted at your home, as is normally required for standard billing. You may switch back to standard billing at any time, without any fees.

(4) OG&E should be required to track and report, at minimum, the following information to the AG and PUD on an annual basis: (a) program costs and savings to the Company, including customer debt recovery/reduction, (b) frequency and duration of all disconnections, and (c) income information concerning all PayGo customers.

(5) The preceding requirements should be included in OG&E's PayGo Tariff, in addition to the following information: (a) the initial account balance required to initiate a PayGo account; (b) the minimum threshold account balance at which customers will be affirmatively notified by OG&E of their account level; (c) the manner by which customers will be affirmatively notified by OG&E of a low account balance (text, email, letter, etc.); and (d) the manner by which OG&E will collect arrears from customers enrolled in PayGo.

(6) OG&E should consider additional options for its standard, post-pay customers, including text and email notifications, to assist them to better understand the link between their behavior and their energy bills.

(7) OG&E should be required to identify in this Cause which Commission rules with which it intends not to comply in order to implement PayGo, and to request a waiver from such rules.

(8) Two years after the final order is issued in this Cause, OG&E should be required to file an application with the Commission seeking Commission review of PayGo, and Commission approval to maintain the program.

Rebuttal Testimony (April 11, 2016)

On April 11, 2016, Mr. Farrar filed Rebuttal Testimony to the Responsive Testimony of Robert C. Thompson of PUD. Specifically, Mr. Farrar's Rebuttal Testimony was offered to rebut Mr. Thompson's recommendation that all short-term incentives and twenty-five percent of long-term incentives be recovered in rates. Mr. Thompson stated that the short-term incentive plan is not driven by profits of the Company, but is instead driven by goals set for individual employees. Mr. Thompson also argued that because any gains or efficiencies realized through long-term incentives are shared with ratepayers when a rate case is filed, twenty-five percent of those costs should be borne by ratepayers.

Mr. Farrar testified that Mr. Thompson's recommendations represent a significant expansion of the incentives PUD considers appropriate for mandatory recovery from ratepayers. The Commission in past years has excluded one-half of short-term or annual incentives, and all of the long-term incentives from rate recovery, compared to PUD's recommendation in this Cause to include in rate recovery all of the annual incentives and one-quarter of the long-term incentives. In the pending general rate case for Public Service Company of Oklahoma, PUD recommended that the Commission continue to exclude one half of annual incentives and all of the long-term incentives from rate recovery. PUD's recommendation in this Cause represents a significant policy change from its recommendations in previous rate cases. Further, PUD provided no support for this change in policy.

Mr. Farrar testified that Mr. Thompson may have overlooked some of the information related to the nature of the incentives OG&E is requesting in this rate case. Mr. Thompson states on page 27 of his Responsive Testimony, beginning on line 9: "The Company's short-term incentive plan is not driven by profits of the company but is driven by other goals set for individual employees and should be included." The statement that the short-term incentive plan is not driven by profits is at odds with information provided by the Company. OG&E's discovery response AG 3-5_Supplemental clearly shows that $26,749 of OG&E's short-term incentives and $1,071,916 of the holding company's short-term incentives are based on consolidated earnings per share, which includes profits for both utility operations and non-utility affiliate operations. Those incentives are clearly based on Company profits.

Unregulated companies do not have captive customers and cannot increase their prices to cover incentive compensation. If an unregulated company increases its charges above levels charged by its competitors, its customers are free to take their business elsewhere. An unregulated company's incentive compensation must be effective without increasing the company's prices. In contrast, in the case of a public utility, other businesses are barred from offering competitive service. For public utilities, the increase in rates for any cost that is not essential for the service being provided, or is not primarily beneficial to its ratepayers, essentially forces the public to bare a cost imposed to benefit another group - shareholders. A public utility does not have to pay a bonus to its employees to increase its earnings, but instead can seek relief from its regulator if earnings are below levels for comparable companies. The rates charged by a

public utility are set by a governmental agency, unlike the fees and charges of a competitive market company. If the Commission thinks ratepayers should pay for Company incentives, Mr. Farrar suggested that the OCC eliminate all incentives from rates and provide a line on the ratepayer's bill for a voluntary bonus or "tip" if the ratepayer thinks his service has been extraordinary. Otherwise, it remains inappropriate to increase a captive customer's rates for the mandatory recovery of financial incentives.

Paul J. Wielgus

Paul J. Wielgus, Managing Director of GDS Associates, Inc., an engineering and consulting firm, filed Redacted Responsive Testimony on March 21, 2016 on behalf of the Oklahoma Attorney General ("AG"). The purpose of Mr. Wielgus' testimony is to present the findings and recommendations of the AG in this case with regard to:

(1) Oklahoma Gas and Electric's ("OG&E") proposal to transfer to its retail customers approximately 300 Megawatts ("MWs") of existing generating assets previously allocated to serve its wholesale customers; and

(2) OG&E's proposal to increase the Operating and Maintenance ("O&M") costs to account for expenses from OG&E's holding company that will no longer be allocated to OG&E's non-regulated affiliate.

Mr. Wielgus concluded that subject to the conditions outlined in his testimony, OG&E should be permitted to transfer to its retail ratepayers approximately 300 MWs of existing generating assets that were previously used to serve its wholesale customers. Mr. Wielgus also concluded that OG&E should not be permitted to increase its O&M to account for costs previously assigned to its affiliate; OG&E's holding company has been unable to reduce or transfer those costs to a new stand-alone company that has since succeeded the affiliate to which the costs were previously assigned. Mr. Wielgus based his conclusions on the following: Although OG&E did provide a comparison of the $/kW cost of the existing generating capacity to the cost of new generating capacity, OG&E did not disclose the downside risks to the retail ratepayers associated with the transferred generating capacity. Under OG&E's proposal, all of these risks and costs would be transferred to the retail ratepayers. The increase in O&M is not a necessary expense to serve OG&E's customers. The increase is the result of a contract between OGE Energy Corp., which is OG&E's holding company, and an affiliate of OG&E.

Mr. Wielgus recommends:

1. The Commission should allow the transfer to its retail ratepayers of approximately 300 MWs of generating assets at the cost of $283/kW, but with certain conditions attached to the transfer. Going forward, retail ratepayers should only be responsible for appropriate ongoing O&M and other expenses associated with this transferred capacity. The retail ratepayers should not be subject to recovery of capital expenses, and new O&M expenses associated with the capital expenses, identified in OG&E's generating plant study dated January 2012; nor environmental compliance capital projects, and new O&M expenses associated with these environmental compliance capital projects; nor any retirement costs.

2. The Commission should deny OG&E's proposed increase in O&M of $6,057,685 for holding company expenses that will no longer be allocated to OG&E's affiliate. These costs are not a necessary expense to serve OG&E's retail ratepayers.

Statements of Position

OG&E Shareholders

OG&E Shareholders Association ("OG&E SH") submits this Statement of Position in lieu of responsive testimony pursuant to the Procedural Order entered in this cause.

OG&E ("Applicant", "OG&E", or "Company") filed this Application seeking Commission review of OG&E's rates, charges and tariffs and for the establishment of fair and reasonable rates and charges for retail electric service within the State of Oklahoma. The Company requests in this cause that the Commission issue an order authorizing OG&E to adjust its retail rates subject to the jurisdiction of the Commission, authorizing OG&E to file changes in tariffs and terms and conditions of service as set forth in the Application, as well as all other relief requested in the testimony and exhibits filed herein by OG&E.

OG&E Shareholders Association supports the request for approval of an increase in its rates of $92.5 million as compared to OG&E's rates that were implemented in August 2012. OG&E Shareholders Association also supports OG&E's request to achieve a 10.25% return on equity. OG&E SH concurs in the position of the Company that such a return on equity is fair, just and reasonable.

The OG&E Shareholders Association notes that the procedural schedule allows for additional discovery and the filing of rebuttal testimony, and, therefore, reserves the right to fully participate in the remainder of this proceeding as scheduled, including to cross-examine witnesses on all issues at the hearing on this matter. OG&E Shareholders Association reserves the right to amend this Statement of Position should circumstances change or if information not previously known becomes available in the course of this proceeding.

Federal Executive Agencies

The Federal Executive Agencies ("FEA") submits the following assessment of its position concerning Oklahoma Gas and Electric Company's ("OG&E" or "Company") proposed increase in electric revenues, and related impact on retail customer rates. FEA's position concerns the development of the revenue requirement deficiency, spread of the deficiency across rate classes, and proposed rate design.

I. Revenue Requirement

FEA filed responsive testimony on revenue requirement issues, and also supports adjustments proposed by other parties. FEA's proposed adjustments to OG&E's claimed revenue deficiencies are summarized as follows:

I.A. OG&E's claimed revenue deficiency is overstated because its rate of return on investment is not just and reasonable. OG&E's claimed revenue deficiency is based on a return on equity of 10.25%, which is at the low-end of its witness's range of 10.25% to 10.75%. FEA's expert cost of capital witness, Christopher C. Walters, demonstrates in his testimony that a fair and reasonable range for a return on equity in this proceeding for OG&E is 9.0% to 9.60%. FEA proposes the midpoint of the range for setting rates, or 9.3%.

Mr. Walters also explains that the Company's proposed capital structure, which includes a common equity ratio of 53.31%, is unreasonably high. He explains that using a capital structure composed of a common equity ratio that is too high unnecessarily increases the Company's revenue requirement and claimed revenue deficiency. A balanced capital structure will ensure the utility's financial integrity is preserved, but at more reasonable cost to customers. A more reasonable capital structure for OG&E would be approximately 50% equity and 50% debt. Mr. Walters supports this finding by a review of authorized rates of return for electric utility companies across the country, a review of credit metric benchmarks to support OG&E's credit strength, and a general assessment of the impact on revenue requirement by using a balanced capital structure, rather than OG&E's proposed excessive equity weighted capital structure.

Mr. Walters concludes that if the Oklahoma Corporation Commission ("Commission") does not adjust OG&E's proposed capital structure, that the equity weight in the capital structure should be considered in awarding a fair return on equity in this proceeding. By overstating the common equity weight of total capital, the financial risk decreases, and the return on equity should be lower to reflect this reduction in financial risk.

I.B. OG&E also proposes certain modifications to the Company's proposed depreciation rates. FEA witness Brian C. Andrews demonstrates that the Company's proposed new depreciation rates are excessive for specific accounts. The proposed adjustments outlined by Mr. Andrews include the following:

a. Company witness Spanos proposed average service lives for several of OG&E's transmission and distribution ("T&D") accounts that were too short, resulting in depreciation rates that are excessive. FEA witness Andrews demonstrated by utilizing statistical fitting methods, that the survivor curves utilized to determine the depreciation rates for these assets should have increased average service lives. This results in longer service lives for the T&D accounts for which the Company proposes to seek depreciation rates. The depreciation rates for Accounts 350.2, 353, 353.1, 355, 356, 362, 364, 365, 366, 367, and 369 should be decreased to more accurately reflect longer service lives that have been justified using statistical fitting methods.

b. Mr. Andrews proposes disallowing the Company to recover terminal dismantlement costs for its Steam and Other production assets. Mr. Andrews' outline states that OG&E has not produced any studies supporting its proposed dismantlement expense, nor has it proven that recovery of dismantlement expense is just and reasonable. Without any sort of dismantlement cost study, the Company's proposal in this case

simply cannot be accepted as just and reasonable and a prudent treatment of these resources.

c. Mr. Andrews outlines that some of the infrastructure in place at these production sites could potentially be utilized for the next generation of power plants. If existing infrastructure can be utilized for the next generation, both dismantlement expenses for the current generation of power plants would be reduced and development costs of the next generation would be reduced. All of this suggests that the Company's proposal to recover dismantlement costs, without a full dismantlement cost study, is simply not just and reasonable and likely will result in excessive charges to retail customers.

d. Mr. Andrews proposes that the Commission order OG&E to conduct a fully developed dismantlement cost study to assess the infrastructure on existing sites for dismantlement or for retention for future generation resources before the proposed dismantlement cost are allowed to be recovered from retail customers.

e. Based on FEA witness Andrews' proposal to adjust depreciation rates, and remove dismantlement cost, FEA finds that the Company's depreciation expenses are overstated by approximately $37.2 million.

I.C. Other Revenue Requirement Positions

FEA will review in detail the proposed revenue requirement adjustments made by other parties, and OG&E's response to same. FEA reserves the right to support other parties' proposed revenue requirement adjustments that are proved to be just and reasonable.

II. Class Cost of Service Study

1. FEA witness Michael P. Gorman responds to the Company's class cost of service study. He finds that the Company's class cost of service study is generally reasonable but comments on whether or not it properly reflected losses in the development of demand allocation factors. Mr. Gorman asserted that not properly adjusting demand metered billing units for losses, will produce demand allocation factors that over-allocate demand-related costs to customers served at high delivery voltage levels, and under-allocate demand-related costs to customer served at lower delivery voltage levels.

   Mr. Gorman recommends the Commission direct OG&E to explain or modify its class cost of service study for this important cost feature related to delivery service voltage. Mr. Gorman observes that the Company did accurately adjust its energy billing units for delivery voltage losses in developing energy allocation factors, the same should be done for demand units.

III. Proposed Rate Design

1. FEA witness Gorman took issue with the Company's proposed rate design for its Large Power and Light – Time-of-Use ("LPL-TOU") rates. Mr. Gorman observed that the

Company offers five Service Levels under LPL-TOU (Rate 35) service. Those Service Levels distinguish cost for distribution equipment and delivery voltage losses in deriving OG&E cost of service to customers to price customers served by Rate 35.

2. Mr. Gorman observes that the LPL-TOU Service Level 1 rate is a service function where OG&E incurs very little to no distribution service costs. Its distribution costs to these customers on this rate is de minimis because these customers take service from customer-owned substations, and the distribution service relates only to the radial line tap from OG&E's transmission system to the customer substation.

   The distribution cost for LPL-TOU Service Level 1 reflects OG&E's lowest cost for all Service Levels in Rate 35, Mr. Gorman observed that LPL-TOU Service Level 1 and Service Level 2 are reasonably comparable to one another with the exception of the cost of distribution service.

   Mr. Gorman objected to OG&E's proposal to substantially change the pricing characteristics of Service Level 1 versus Service Level 2. OG&E's current pricing structure has Service Level 1 lower than Service Level 2 to reflect a difference in distribution cost of providing service to customers on each of these Service Levels. OG&E's cost of service study states that its distribution cost would justify a reduction in demand charge of approximately $0.80/kW-month for customers on Service Level 1 versus Service Level 2. The existing rate has a Service Level 1 demand charge of approximately $0.60/kW-month lower than Service Level 2.

   However, OG&E proposes to reduce the discounted demand charges for Service Level 1 to approximately $0.12/kW-month.

   Mr. Gorman observed that this is not consistent with OG&E's cost of service study, and should be denied. Further, OG&E proposes to increase the on-peak energy charge for Service Level 1 versus Service Level 2 customers. Mr. Gorman observed that this proposal is inconsistent with the current rate design for Service Level 1 and Service Level 2, and has not been rationalized or explained by OG&E.

3. Mr. Gorman also observed problems with the accuracy of OG&E's estimated cost of service for LPL-TOU rate structures. First, he observed that the Company's class cost of service study appears to not have reflected losses in the development of demand allocation factors. He states that this results in the over-allocation of cost to customers taking service at high delivery voltage such as Service Level 1 customers, and understating the costs that should be allocated to lower delivery Service Level customers such as those taking service at Service Levels 3, 4 and 5. The second problem Mr. Gorman observed with the Company's class cost of service study is an inconsistency in the demand factors used to develop the LPL-TOU demand allocation factors, and the demand factors used in OG&E's proof of revenue. The discrepancy in the demand between demand allocation factors and proof of revenue suggests that too much costs have been allocated to LPL-TOU Service Level 1 customers. Because of these discrepancies in the class cost of service study, Mr. Gorman recommended maintaining

the existing rate structure of LPL-TOU, but simply adjusting the rates to reflect the allocated cost of service to the LPL-TOU Rate 35 group.

Oklahoma Sustainability Network

OSN has given careful consideration to OG&E's proposed new demand charge, the much higher mandatory monthly customer charge, and the reduced value for kilowatt hours. OSN's primary concern is with the ability of customers to respond to these changes, and the likely impacts on ratepayer energy efficiency (EE) investments. OSN has an established history of encouraging and supporting OG&E's successful and growing EE programs.

OG&E residential and small commercial customers have invested millions of dollars to upgrade and weatherize their homes and businesses in order to reduce their energy consumption and lower their costs of electricity. The large majority of these customers based their investment decision on the assumption that their costs would be recovered in a reasonable amount of time by a substantial reduction in the known and established kilowatt hour (kWh) charges on their bills.

OSN believes that OG&E's proposed three-part rate structure, with its much lower value for a saved kWh, undermines these customer investments. OSN also is concerned that it threatens the success and budget of the EE programs going forward. The proposal for a drastically higher mandatory monthly customer charge (fixed charge), along with the demand charge, will reduce customers' ability to control their bills and will increase the cost of inducing customers to save energy, including the necessity for higher incremental rebates for OG&E's efficiency programs.

MONTHLY FIXED CHARGES

While doubling the flat monthly charge, OG&E also is proposing to slash Winter Season residential kWh energy prices by 70%. At less than two cents per kWh, OG&E's proposed rate design would leave customers with almost no economic motivation to conserve energy and could in fact promote wasteful usage of electricity. This shift in the way OG&E wants to collect its costs - with a much lower value for saved kilowatt hours - is contrary to the goals of encouraging reduced usage by customers. OSN recognizes that OG&E is one of a number of utilities in various states seeking to increase the monthly customer charge. But we also note that OG&E's proposed $26.54 charge would leave OG&E customers paying in the top tier of these charges in the nation.

DEMAND CHARGES

OG&E's well-known "2020 Goal" and its widely promoted SmartHours program have educated residential and small commercial customers as to how important it is to reduce usage during peak demand. But OSN believes that OG&E's proposed non-coincident demand charge, along with the corresponding extremely low energy price, sends an inconsistent and contradictory message to customers on the value of reducing usage during peak times. It does not convey an accurate price signal about the times when electricity is most expensive to produce.

OSN strongly believes that informed decisions are crucial, but we do not believe that customers understand demand charges, we doubt that demand charges will be easy to explain, OG&E has not provided a plan or enabling technology that would help with this gap in customer knowledge - and we doubt that a majority of even well-informed customers will be able to consistently modify their behavior in response to this type of charge and avoid excessive bills.

To avoid high demand charges, customers would need to be very careful with the operation of their appliances, but OSN notes that very few customers know or have access to the kW demand of all electricity consuming devises in their homes. In our experience, many homeowners do not even know, for example, whether their dryers are electric or gas - yet a typical electric dryer can require 4 kW or even 5 kW of demand. OSN also notes that some appliances, like water heaters and refrigerators, operate automatically and are not in the immediate control of customers. For a customer with a typical monthly peak demand of 8.5 kW, and little ability to reduce it, the mandatory, unavoidable portion of their bill, including the doubled customer charge, will increase from $13.00 to nearly $50.00. For small usage customers this amount would be well more than half of their bill.

Faced with a new and unfamiliar bill component that they do not understand, and not having access to enabling technology, OSN believes that most customers will not know how to respond to the demand charge, and it will become simply another mandatory fee.

CONCLUSION AND SUPPORT OF ADOPTION OF JOINT STIPULATION

OSN is opposed to the new demand charge and doubling of the mandatory monthly charge to $26.54. Prior to the conclusion of the hearing on the merits in this matter, all of the parties, other than OG&E and its shareholders, were able to reach a Joint Stipulation and Settlement Agreement on issues related to rate design and cost of service raised in this case. OSN strongly supports the Joint Stipulation and recommends the Commission adopt the Joint Stipulation as its determination of the issues set forth therein.

AARP

1. THE COMMISSION SHOULD PROTECT RESIDENTIAL CUSTOMERS FROM OG&E'S REQUEST TO SUBJECT THEM TO DEMAND CHARGES THAT UNDERMINE SMART METER AND ENERGY EFFICIENCY INVESTMENT

OG&E is proposing a radical, untested, controversial and discriminatory new rate design that adds a mandatory demand charge to its standard default residential tariff—it's mostly highly subscribed residential tariff. OG&E's demand charge proposal has not been accepted by any utility commission in this country. Moreover, it is not designed to respond to meet the requested needs of its customers (as OG&E attempts to claim though a "customer survey"). It is not developed to solve any revenue deficiency issue of the utility, which can be addressed via its current rates structure. And with its non-coincident peak calculation, it has no impact on reducing system peak demand and related utility costs.

OG&E's proposal not only will result in a large portion of OG&E's low use and low income customers hit with bill increases that could be 100%, OG&E is expecting these low use and low income customers to expend additional funds to buy exciting things like home management systems, load controllers and batteries in order to be able to cope with demand charges. AARP does not believe demand charges should be considered for residential customers at any time in the near future. The Commission should send a strong signal that attempting to impose demand charges on residential customers is a road to nowhere.

The Commission should completely reject in total OG&E's request to redesign its default residential tariff in a manner to include demand charges that are unfair, discriminatory, untested, and contrary to the efficient use of electricity.

2. REJECT OG&E'S REQUEST TO EXPAND COSTS INCLUDED IN THE MONTHLY FIXED CHARGE

For its residential customers, OG&E is requesting to increase its mandatory monthly charge from $13.00 to 26.54 per month. This increase is based on OG&E's attempt to ignore fundamental principles of rate design and change the allocation of distribution costs that are normally recovered in variable charges on a kWh bases into a "fixed" monthly charge. This change is a violation of long-held and applied rate making and cost allocation principles and a backdoor move to have this Commission adopt what is known as Straight Fixed Variable ("SFV") Rates.

Monthly "customer charges" were developed to recoup costs related solely to metering, billing and customer service as fixed a monthly charge to customers. A monthly "customer charge" was NOT developed recover distribution, transmission or generation costs, contrary to OG&E's request to expand the costs recouped through this charge. OG&E goes further to then allocate certain distribution costs into the customer charge. OG&E attempts to argue that these are "fixed costs," apparently confusing a fixed asset for a fixed cost. This runs contrary to appropriate rate design methodology.

The National Association of State Utility Consumer Advocates ("NASUCA") issued a landmark resolution of more than 40-State Assoc. of Consumer Protection Officials calling for state commissions to "reject utility 'fixed charge' approach as unreasonable and unfair for low-income, elderly, and minority customers" and issued a resolution entitled *Opposing Gas and Electric Utility Efforts To Increase Delivery Service Customer Charges*.

The Commission should reject OG&E's request for Straight Fixed Variable rate design that expands monthly fixed charges to include distribution costs; determine that OG&E's calculation of the monthly customer charge should ONLY include metering, billing and customer care costs; and to increase transparency, the Commission should require OG&E to line item the monthly customer charge on customer bills.

3. SERVICE INITIATION AND RECONNECTION FEES SHOULD BE ELIMINATED

Currently OG&E charges fairly high fees to initiate service and to reconnect service ($25.00 and $35.00, respectfully). Both of these actions bring a paying customer on to its system

to contribute to utility revenues. OG&E is seeking small reduction is these fees, when they previously testified that customers would see substantial reductions or even elimination of the fees due to customer investment in smart meters. Public Service Company of Oklahoma ("PSO") in its pending rate case is in fact eliminating these charges to customers altogether. In order to attempt to maintain some level of these charges, OG&E is requesting to move costs previously recovered in base rates for clerical salaries and wages into the fees.

The Commission should require OG&E to eliminate all Service Initiation and Reconnection Charges as smart meters allow for fast and remote service activation; smart meter costs and customer service costs that are being requested by OG&E in these charges are already recovered in base rates. Elimination of these charges are exactly the types of direct benefits customers were promised by OG&E when it sought hundreds of millions of dollars from customers in order to pay for smart meters.

4. ALLOCATION OF RATE CASE IMPACTS SHOULD BE PROPORTIONALLY BORNE BY ALL CUSTOMER CLASSES

As proposed by OG&E, the rate design allocates a higher percentage of its requested increase to come from the residential class. AARP recommends that any rate impact outcome in this matter should be allocated as a weighted percentage across all customer classes, with no shifting or change of rate recovery from one class to another.

The Commission should allocate any rate impact proportionally across all customer classes, with no shift or change in rate recovery from one class to another.

5. SMART METER OPT-OUT FEES AND MONTHLY SURCHARGES

OG&E is proposing to include new one-time and monthly recurring fees for customers pursuant to a smart meter opt out rider. In addition to the opt-out charges, OG&E customers will also be paying for full smart meter deployment and the cost of stranded analog meters in their rates. AARP did not see any evidence that OG&E would incur any incremental costs that could not be met with its current labor force (which is already included in OG&E's rates) to serve this small contingency of customers.

For any smart meter opt out rate, the Commission should consider only incremental costs to serve these customers and should insure any ultimate rate meets the test of reasonableness and is fair and affordable to any customer – rich or poor – that may wish to avail themselves of this option.

6. PRE-PAY BILLING SHOULD BE REJECTED AS OG&E HAS FAILED TO PROVIDE ANY EVIDENCE TO SUPPORT ITS PROPOSAL AND VOID OF ANY DETAILS AND CONSUMER PROTECTIONS

7.

In this case, OG&E is proposing to add a prepay electric bill payment option (referred to by OG&E as pay-as-you-go or PayGo). The Commission should be aware that pre-pay electric service is highly controversial and participation skews heavily toward lower-income consumers.

There is a viable concern that pre-pay services will be targeted at low income consumers and those with outstanding balances that they have difficulty paying. OG&E fails to provide any evidence of a need for prepay services, that such services will be cost effective or beneficial to customers, that it will not be disproportionately subscribed to by low-income customers or those with outstanding balances or that disconnections will not occur at a rate higher than non-prepay subscribers, among other matters.

Based on the lack of evidence and the complete absence of any program details within the proposed tariff, the Commission should outright reject OG&E's request to offer pay-as-you-go billing service at this time. If any program is considered, it should be limited to two years and include consumer protection provisions and reporting requirements, which can be used to determine if it is in the public interest for the program to continue beyond two years.

8. AARP SUPPORTS OG&E'S REQUEST TO ELIMINATE 6 RIDERS – BUT OPPOSES THE ADDITION OF A VEGETATION MANAGEMENT TRACKER AND NEW RIDER CALLED THE "MANDATORY ENVIRONMENTAL RECOVERY COST RIDER"

OG&E, because it has completed collection of costs between rate cases, is now rolling those costs into rate base, which results in the termination of six riders. As this Commission is well aware, AARP strongly opposes the use of riders as a means to increase collection of revenue between rate cases and are used to shift risk from shareholders to ratepayers.

The Commission should be aware that just because a rider is being eliminated does not mean customers are not still subject to those costs. The riders have allowed OG&E to recover costs from customers without having to have its revenues evaluated via a rate case. As the Commission is aware, OG&E was required by no less than three Commission orders to file a rate case in 2013 – all three of these orders related to granting riders that were to be reviewed in a 2013 rate case. OG&E ignored those orders. The Commission should continue to strictly evaluate costs that are sought for rider recovery and such actions should only occur in extraordinary circumstance.

The Commission should reject the establishment of a new vegetation management tracker and the Mandatory Environmental Recovery Cost Rider. The Commission should continue to evaluate requests based on the rider recovery standard: (1) the costs are largely outside the control of the utility; (2) the costs are unpredictable and volatile; and (3) such costs are substantial and reoccurring, and have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a rate case.

9. RETURN ON EQUITY SHOULD BE NO GREATER THAN 9.25%

OG&E's requesting an ROE of 10.25%. As stated in all of the non-utility witness calculations, OG&E is a monopoly utility operating a low-risk business. AARP supports the Oklahoma Attorney General and Public Utility Division Staff's calculation of ROE at 9.25% as described and set forth in the Responsive Testimony of Solomon and Garrett. AARP believes

based upon the evidence provided of OG&E's low risk profile combined with its reliance on higher cost equity, 9.25% provides an appropriate level of ROE.

The Commission should grant a ROE of no more than 9.25% as identified by the Attorney General and Public Utility Division Staff.

10. REJECT EXPANSION OF FUEL CLAUSE FOR NON-FUEL COST RECOVERY – AQCS OR WIND PTCS

As to the AQCS costs (which include costs for materials like limestone and ammonia and certain O&M costs), these are not fuel costs and should not be recovered through the fuel adjustment clause. These costs, as may be deemed appropriate in the test year, may be recovered by the utility in its general rates.

AARP requests the Commission reject the recovery of non-fuel costs through the fuel adjustment clause, particularly OG&E's request to recover future consumable costs and flow decreasing revenues from production tax credit reductions.

11. DENY TRACKER TREATMENT FOR VEGETATION MANAGEMENT AND DENY REQUEST TO INCREASE FUNDING

It is management's responsibility to use revenues at its discretion and if it needs to spend funds on vegetation management in order to comply with the rules, it is required to do so – regardless of what it claims are "reflected in rates." As with aspects of all Company operations, the Company is given an overall budget for its operations through its rates and then management decides how to spend that money. Just because management made a decision to not allocate necessary funds for vegetation management, does not mean the Company lacks resources to meet its vegetation management requirements.

In the 2011 rate case, AARP argued that ratepayers and the Commission should demand that the Company actually demonstrate that expenditures achieve actual documented improvements to the system. Based on 2009 data available for the 2011 rate case, AARP used the Institute of Electrical and Electronics Engineers ("IEEE") annual surveys of electric distribution utility reliability performance and showed that OG&E's performance did not reflect the 1st Quartile performance of comparable utilities. AARP noted that even in 2011 after implementing its "hardening" program with millions of dollars from a rider, OG&E's restoration times had increased, not decreased.

The Commission should find that OG&E is in violation of OAC 165:35-25-15 and require quarterly and annual reports regarding the Company's vegetation management efforts and their correlation to improved system reliability. As recommended by the Attorney General, the Commission should reduce non-cycle work by $657,027 to match the five-year average cost and reduce the budget for distribution cycle trimming by $4,354,171 that can be achieved by moving to a two-tier cycle that matches with industry best practices.

CONCLUSION

AARP respectfully requests the Commission, after consideration of the evidence in this matter, to make the following determinations regarding certain requests of the utility in this Cause:

1. Reject OG&E's proposal to impose demand charges in its default residential tariff, which does not reduce peak energy consumption, penalizes low income and low use customers and does not reduce utility costs;

2. Reject the inclusion of distribution costs within a customer's monthly fixed charge, which results in a 100% increase to monthly fixed charges;

3. Eliminate service initiation and reconnection fees as smart meters provide for remote connection of service;

4. Allocate any rate impacts (whether increase or decrease) proportionally among all rate classes equally;

5. Smart meter opt-out charges should only reflect incremental costs and should not be cost-prohibitive and, therefore, limited to only financially well-off customers;

6. Pre-pay billing option should be denied as OG&E failed to provide any evidence in support of its proposal and is void of any details, including adequate consumer protection provisions;

7. Accept elimination of six riders with appropriate audit of recovery levels that are being included in base rates and reject the request for two new riders – Vegetation Management Tracker and Mandatory Environmental Recovery Cost Rider;

8. Determine return on equity at 9.25%;

9. Reject use of the fuel adjustment clause for recovery of non-fuel expenses (consumables and production tax credits); and

10. Make certain adjustments to vegetation management budgets and deny the addition of tracker.

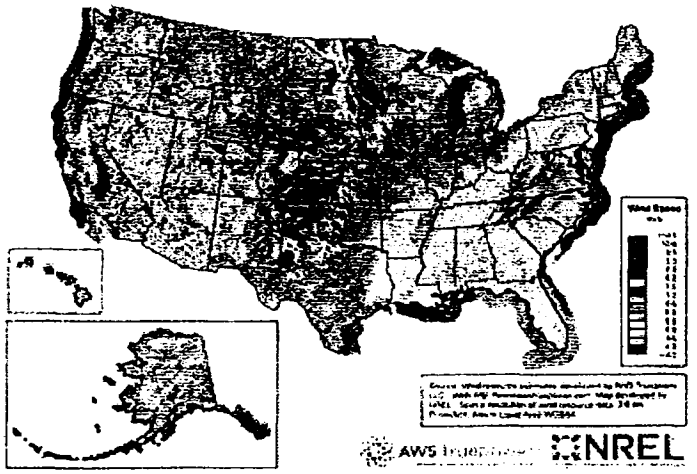
JOINT STIPULATION AND SETTLEMENT AGREEMENT ON RATE DESIGN AND COST OF SERVICE ISSUES

During the hearing on the merits, all of the various parties – other than the utility and its shareholders – participated in extensive negotiations in order to resolve issues related to rate design and cost of service. AARP noted during the hearing that rate design and cost of service issues are revenue neutral to the Company and are of vital importance to the way the revenues are collected from various customer classes. This would leave the Commission with only having to determine the revenue requirement for the Company. At the hearing, the Joint Stipulation and Settlement Agreement on Rate Design and Cost of Service Issues was presented and AARP strongly supports the full adoption of the Joint Stipulation as a fair a full determination of the rate design and cost of service issues.

Wind Coalition

Oklahoma sits in the heart of America's Wind Corridor, that central region of our country blessed with tremendous and valuable wind energy resources. Thanks to the blessings of geography and topography, Oklahoma has abundant and varied sources of energy including oil,

natural gas, solar energy, and the infinite kinetic energy found in the winds that blow across the state.



Thanks to technological advances, wind energy is no longer "alternative" energy. It has become a mainstream, reliable, and cost-effective source of affordable energy. Today, approximately 17% of Oklahoma's electricity needs are met by wind power, which saves millions of gallons of water, reduces air emissions, lowers costs for consumers, and grows rural economies.

As Oklahoma wisely pursues an "all of the above" approach to energy production, wind energy has grown as a key source of electricity generation, complementing the state's natural gas-fired, coal-fired, and hydro-electric generation fleets. Oklahoma's wind blessings have attracted massive capital investments to the state, bringing economic opportunity and tax revenue to long-neglected rural areas of the state and lowering all Oklahomans' electricity bills.

Oklahoma has become the fourth largest wind energy state and growing, with an estimated 5,000 megawatts of capacity as of the end of 2015—enough energy to power up to 1,500,000 American homes.[32] Wind energy companies have invested more than $6 billion during the development and construction of 29 wind farms located in the state of Oklahoma.

According the Southern Power Pool ("SPP") 2016 Wind Integration Study ("SPP 2016 Study"), SPP wind generation resources are primarily located in the southwestern and north central portions of the SPP footprint. Wind energy has grown over the last several years as additional bulk transmission has been added to the footprint and represented approximately 14% of total system capacity at the end of 2015. Wind development is expected to expand to higher levels based on the generation interconnection requests in the queue.[33] The SPP 2016 Study proposed recommendations that would increase transmission reliability and provide additional

[32] Using estimates provided by the Executive Office of Energy and Environmental Affairs, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/wind/wind-energy-facts.html#c
[33] SPP 2016 Wind Integration Study, p. 7.

reliability capabilities as additional renewable capacity is installed throughout the SPP region.[34] Viewed collectively, the SPP Study and Recommendations suggest that the SPP sees wind as not only an integral part of the current grid, but also a form of energy whose expansion should be responsibly fostered and encouraged by the SPP and its member utilities.

With Oklahoma's incredible wind energy resource, wind power now offers some of the least expensive power available to Oklahoma consumers and industries. The price of that power is fixed for a considerable length of time (approximately 20 years in most cases), providing predictability and an important pricing hedge when paired with energy generated using fuels from other sources, such as natural gas.

But low power prices are only part of the story. By using Oklahoma's own resources to power the state, consumers keep more of their energy dollars invested in their communities, growing the state's economy and increasing the tax base. Since 2003, Oklahoma wind energy projects have paid approximately $1 billion in ad valorem taxes, and including these taxes, the wind industry is predicted to contribute over $1.2 billion to education funds.[35] Furthermore, wind energy projects have long life expectancies, meaning decades of tax revenues for the communities in which they operate.

Wind energy projects help keep farmers and ranchers on their land by providing a new revenue stream for landowners. Because wind power developments typically leave 95-98% of the land on which they sit available for agricultural purposes, agricultural production can continue while new income is generated from the harvest of wind. For many struggling agricultural producers, this windfall has been critical to their survival. According to a study conducted for The Wind Coalition by The Economic Impact Group of Edmond, Oklahoma, wind energy projects provide more than $22 million annually in payments to local landowners, and approximately $15 million in direct wages to local workers.

Wind energy investments also provide great benefits to the environment in Oklahoma. Wind power produces no emissions, making compliance with federal and state air quality standards more attainable and offering health benefits to consumers. The wind power installed in Oklahoma will avoid 13,000,000 tons of carbon dioxide emissions a year, the equivalent of taking more than 2,000,000 cars off the road.[36] Electricity generation is a major user of water, second only to agriculture, but wind power uses no water when generating electricity. Today's Oklahoma wind energy generation fleet saves approximately 3.5 billion gallons of water each year.

From the time the first settlements were built in the state, Oklahomans have lived with the wind and harvested its strength to power their lives. Today, its citizens are still embracing wind as an energy source for their future, because Oklahomans know that development of Oklahoma's wind resources benefits their state economy and their communities. As the public

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[34] *Id.*, at pp. 7-8.

[35] Dr. Shannon L Ferrell and Joshua Conaway, "Wind Energy Industry Impacts in Oklahoma." Oklahoma State University, Department of Agricultural Economics: Oklahoma. September 3, 2015.

[36] Using estimates provided by the Executive Office of Energy and Environmental Affairs, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/wind/wind-energy-facts.html#c

calls for reliable, water-saving, inexpensive, home-grown sources of power, the wind will continue to emerge as a viable, pollution-free, complementary energy resource. The WC's position is that Oklahoma Gas and Electric should take advantage of the way in which wind energy provides great benefits for customers, provides cost hedging from fuel and helps avoid excessive capital for the Company, and also enables reduced operation and maintenance cost for OG&E.

Sierra Club

I. Introduction

Sierra Club opposes Oklahoma Gas & Electric's ("OG&E") drastic and unnecessary changes to how residential and small commercial customers will be billed for electric service.[37] OG&E's proposal to double the mandatory customer charge and impose a demand charge based on the customer's peak energy usage is unfair, inequitable, and counter to Oklahoma's goals to encourage demand reduction and alternative energy development.

OG&E's proposed rates are contrary to state energy policy and will ultimately increase costs to serve customers because it will discourage energy efficiency and distributed generation. These rates are unfair to customers who will lose control over their bills and be subject to difficult-to-manage demand charges. The changes will be especially harmful to low usage customers, who tend to be low-income. OG&E has offered no compelling reason for such a drastic change in rate design, in light of these significant problems.

OG&E's requested $26.54 customer charge would be among the highest in the country for residential customers. A February 2016 report from the Consumers Union shows that OG&E's current customer charge is already in the highest quarter of those in major U.S. cities.[38] Even among utilities who have proposed to increase their customer charges, OG&E's request is exceptionally high—only two other utilities (neither investor-owned) have even proposed charges above $20.[39]

If the doubled customer charge was not enough of a shock for customers, OG&E's proposal to impose a default demand charge on residential customers asks this Commission to be the first in the country to find that such a demand charge is reasonable for residential customers. OG&E's proposal to impose default demand charges on residential customers is unprecedented for a utility of its type.[40] While OG&E's witness Dr. Faruqui testifies that demand charges are common, among the eighteen examples, he offers not a single utility defaults its customers into a three-part rate.

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[37] Although Sierra Club opposes the Company's proposed changes to both the R-1 and GS tariffs, for the sake of simplicity, we will refer simply to residential customers throughout this Statement. However, many of the same circumstances apply to small businesses, who lack dedicated energy managers or resources to control their demand and for whom electric service costs are a significant cost of doing business.

[38] *See Melissa Whited et al., Caught in a Fix: The Problem with Fixed Charges for Electricity*, Prepared for Consumers Union report (Feb. 9, 2016), at Figure 2 (Exhibit MG_2 to Responsive Testimony of Mark E. Garrett on behalf of The Alliance for Solar Choice) (hereinafter "Caught in a Fix").

[39] *Id.* at Figure 3.

[40] *See* Testimony of Mark E. Garrett on behalf of TASC, at 26-27.

Sierra Club continues to oppose the Company's proposed tariff for customers who install distributed generation.[41] State law prohibits the imposition of any surcharges or other tariff changes on distributed generation customers unless required to address a cross-subsidy. As the Company's cost of service study filed in this case demonstrates, no such subsidy exists, even before the benefits of distributed generation are considered.

II. Summary of OG&E's Application

OG&E proposes to make dramatic and confusing changes to its default residential rate, Tariff R-1. OG&E would double the customer charge to $26.54 and introduce a demand charge of $2.75 per kW. The demand charge is based on the "maximum rate at which energy is used for any period of 15 consecutive minutes of the month for which the bill is rendered as shown by the Company's demand meter."[42] In other words, the demand charge is based on the highest 15 minutes of usage in the previous month, regardless of whether that peak 15-minute usage coincides with any kind of utility system or class peak.

The R-1 energy rates will decline significantly as a result. In the summer, residential customers currently pay 5.7 cents for the first 1400 kWh, and a higher price of 6.8 cents for use in excess of that level. Under OG&E's proposal, they will face a flat rate of 4.9 cents per kilowatt-hour. In the winter, the energy rate would decline from 5.7 cents for the first 600 kWh to 1.7 cents for all kWh consumed.[43]

General service customers, including small businesses, will see their customer charge double from $24.70 to $48.50, and for the first time ever will be subject to a demand charge of $2.90 per kW. OG&E proposes to more than triple the customer charge for small public schools, up to $48.50 a month, and impose a demand charge of $2.90 per kW.

OG&E continues to propose separate tariffs for residential and general service customers with distributed generation, which also include demand charges and high fixed charges, as initially proposed in Cause No. PUD 201500274.

III. The Commission Should Reject the Company's Proposed Rates for Residential and Small Commercial Customers

Sierra Club opposes these changes for the following reasons:

- High fixed charges and demand charges are detrimental to energy efficiency and distributed generation. This rate design will lead to higher overall system costs and is contrary to state policies.
- High fixed charges and demand charges are harmful to customers because they result in a bill over which the customer has little control, and shift the burden of revenue recovery to low usage and low income ratepayers.

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[41] *See* Sierra Club's Statement of Position filed November 6, 2015 in Cause No. PUD 2015000274.
[42] *See* OG&E Application Volume 2, Schedule N, Sheet No. 3.
[43] *See* OG&E Application Volume 3, Sheet 3.0 (redline of changes to R-1 tariff).

- OG&E offers no compelling reason to adopt a radically transformed rate structure that is inconsistent with state policy, will increase costs, and harm customers.

A. High customer charges and unmanageable demand charges dampen the incentive for energy efficiency and distributed generation.

The increased customer charge and demand charge encourages energy consumption because they result in much lower energy rates for residential customers. This increase in energy consumption boosts overall system costs because higher demand drives the need for additional energy infrastructure—these system costs must then be recovered from all ratepayers. Under OG&E's proposed R-1 tariff, the summer energy rate will drop by about 15%. To make matters worse from an efficiency perspective, OG&E is eliminating the modest inclining block rate currently in place for the summer, which charged customers more for consumption above 1,400 kWh a month. The R-1 winter energy rate will decline by 70%. The combination of higher fixed charges and lower energy charges sends customers an "all you can eat" signal.

Higher fixed charges reduce the value of a kilowatt□hour saved and therefore the customer's incentive to lower their bills by reducing consumption.[44] Common sense suggests that any customer facing a 15%, much less a 70%, reduction in the price for a product is going to consume more. Customers who are considering whether to invest in energy efficiency measures will be discouraged from doing so, as it will take far longer to recoup their upfront investment.[45] In many circumstances, the longer payback period might mean that a customer never breaks even financially, even where the investment would in fact be beneficial from a total system cost perspective.[46]

The increase in consumption associated with a higher fixed charge can be estimated based on empirical data about the elasticity of demand. While such a calculation is outside the scope of this Statement, to give a sense of the size of the impacts of rate design, Sierra Club refers the Commission to a report on rate design by experts at the Regulatory Assistance Project, who calculated that switching from a rate with a low fixed charge to a higher one could cause a 7 percent increase in residential consumer usage.[47]

As described in the testimony of TASC witness Mark Garrett, the increased fixed charge and demand charge in OG&E's proposed R-TOU-kW tariff will also discourage customers from investing in distributed solar or wind resources that provide important resource diversity, and system and energy benefits.[48] Mr. Garrett calculates that a new distributed generation customer would see 20% higher bills, compared to how a distributed generation customer would fare on the R-TOU rate that applies to current distributed generation customers. Given the significant

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[44] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 16:1-22; *see also* Caught in a Fix, *supra* note 2, at 16.

[45] A higher fixed charge is especially unfair to customers who have already implemented energy efficiency measures in reliance on the previous rate structure.

[46] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 16:11 to 17:11.

[47] *See* Jim Lazar, Regulatory Assistance Project, *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed* (2013), available at www. raponline.org/document/download/id/6516.

[48] *See* Responsive Testimony of Mark E. Garrett on behalf of TASC, at 18-20.

upfront expense of installing these resources, that 20% increase cuts significantly into the savings that such a customer might be hoping to realize.

This Commission would not be the first to reject a proposed fixed charge increase because of concerns about the impact on energy efficiency. In 2012, the Missouri Public Service Commission did so, noting:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[49]

A rate design that discourages energy efficiency and distributed generation development is contrary to state energy policy and will increase costs for consumers in the long run.

1. Disincentivizing Energy Efficiency and Alternative Energy is Contrary to State Policy

A rate design that increases energy consumption and discourages the adoption of alternative energy resources, such as OG&E's proposed R-1 and R-TOU-kW tariffs, goes against the energy efficiency and alternative energy goals set out in the Oklahoma First Energy Plan.[50] One objective of that Plan is to "Promote energy efficiency to preclude the need for new power generation and manage consumers' energy bills."[51] The Plan also notes the state's interest in "[e]ncourag[ing] the evaluation and realization of solar energy potential throughout the state."[52]

The proposed rate design will also undermine the Company's own demand programs. This Commission requires electric utilities like OG&E to develop and implement demand programs in order to "[m]inimize the long-term cost of utility service, (2) [a]void or delay the need for new generation, transmission, and distribution investment, and (3) [e]ncourage and enable utility customers to make the most efficient use of utility capacity and energy and reduce wasteful use of energy."[53]

Because energy efficiency investments will be inherently less economical for customers, OG&E will likely have to increase the incentives it offers customers to install energy efficiency measures, and increase budgets for marketing and customer education about demand management programs. Simply put, OG&E's proposed rate design is at cross-purposes with the

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[49] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-11.
[50] *See* Oklahoma First Energy Plan (2011), available at https://www.ok.gov/governor/documents/Governor%20Fallin's%20Energy%20Plan%20-%20Jan%202012.pdf.
[51] *Id.* at 5.
[52] *Id.* at 17.
[53] Okla. Admin. Code §§165:35-41-2 & 35-41-4.

Company's own demand programs, and the cost-reduction objectives underlying those programs. Despite this conflict, OG&E does not present any analysis of how the new rate design will affect its demand programs.[54]

2. OG&E's Proposed Residential Rates Will Increase Overall System Costs

Because customers will have a lesser incentive to reduce their demand or invest in energy efficiency measures, they will likely consume more electricity, or at the very least, not decrease their consumption. This higher load will invariably require new generating resources (or delay the retirement of existing resources), increase capital and operating costs for the transmission and distribution systems, and increase environmental compliance costs.55 This impact on overall system costs is why OG&E has invested in demand programs with this Commission's encouragement.[56]

Furthermore, this rate structure creates a powerful disincentive for customers to install distributed alternative energy generation systems. OG&E's own cost of service study shows that residential distributed generation customers provide revenue in excess of the utility's cost to serve them.[57] In addition, distributed generation systems offer benefits to the grid that reduce overall system costs.[58] Accordingly, fewer distributed generation systems will mean increased overall system costs and higher rates for other residential customers.

In addition to encouraging higher overall energy consumption, the proposed R-1 tariff will do nothing to reduce peak hour consumption. OG&E's proposed demand charge is not designed to shave system peak, since it charges customers based on their noncoincident peak demand.[59] To the extent that customers do respond to OG&E's demand charges, customers whose individual peak occurs at times other than system peak might actually shift some of their load to peak hours.

OG&E's environmental compliance costs are especially sensitive to a rate design that undermines the economics for demand reduction and distributed generation. To take one example, a recent analysis has shown that thoughtful rate design can go a long way toward a utility's compliance with the Clean Power Plan, by reducing the need to run high-emitting

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[54] *See* OG&E Response to Sierra Club DR 1-21. All OG&E responses to Sierra Club's data requests that are referred to herein, are included as Attachment Sierra Club-1.

[55] *See Caught in a Fix, supra* note 2, at 18-19; see also Responsive Rate Design Testimony of Kathy J. Champion, at 17:12-16.

[56] *See* OK ADC Title 165, Ch. 35, Section 41.

[57] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 32:16-17 ("As shown in Schedule L-1 of the Company's submitted COSS, Residential DG customers are providing a return in excess of their costs.").

[58] *See id.* at 35:3-21 (noting the potential system cost reductions associated with distributed generation systems, when considered over the life of the DG resource); *see also* Sierra Club Statement of Position in Cause No. PUD 201500274.

[59] The Company's decision to impose a noncoincident peak demand charge, rather than one designed to reduce consumption during peak hours is surprising considering that the Company's R-TOU rate has been so successful in reducing system peak. A more forward-looking rate design would be to make the R-TOU rate more attractive to customers through increased education or enhanced bill credits for low-income customers.

peaking resources.[60] The three-part rate that OG&E proposes will instead increase the dispatch of the Company's generating units.

Finally, OG&E should expect to incur increased customer service costs as customers seek help understanding confusing new imposed demand charges, or switch back and forth among plans trying to find one that will allow them greater control or bill certainty.

B. OG&E's Proposed Residential and Small Commercial Rates Are Unfair to Customers

1. High Customer Charges and Demand Charges Take Away Customer Control

Under OG&E's proposed rate structure, customers would have dramatically less control over their bills. The increased R-1 customer charge of $26.54 will make up 23% of the average customer's bill.[61] Riders over which the customer has no control already make up 28% of that bill.[62] Thus, over half of a residential customer's bill is set before that customer consumes a single kilowatt-hour.

When over 50% of the customer's bill is fixed, customers lose the ability to reduce their bills through demand reduction or distributed generation. The Missouri Public Service Commission recognized the importance of customer control in rejecting the recent proposal by Ameren to increase its customer charge:

The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control.[63]

OG&E's proposed demand charge also erodes customer control. Contrary to the broad assertion of OG&E witness Dr. Faruqui, residential and small commercial customers generally lack the information and resources to control their demand. As such, the imposition of demand charges on these customers will take away customers' control over a significant part of their bill. While in theory customers could reduce their bill by reducing their peak demand, OG&E is not providing the tools or information needed to enable customers to do so.

Responding to a demand charge first requires customers to understand what demand means. Most residential customers are unfamiliar with the concept of demand, for the simple

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[60] Jim Lazar and Ken Colburn, Rate Design as a Compliance Strategy for the EPA's Clean Power Plan (Nov. 2015), at https://www.raponline.org/document/download/id/7842.
[61] *See* Attachment Sierra Club-1 (OG&E Response to Sierra Club DR 1-8(e)).
[62] *Id.*
[63] Missouri Public Service Commission Report and Order, File No. ER-2014-0258, *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service*, April 29, 2015, pages 76-77.

reason that they have not ever had to pay attention to it. The customer must also have information about what appliances in their house have the highest demand, and how they can control them, especially pumps, compressors, water heaters, and other high demand appliances that cycle without the customer's direct intervention. Finally, the customer needs to know when and at what level the peak is occurring, so they know how to focus their efforts to reduce demand. Basic information about a customer's peak demand levels is also needed so that the customer can, at a minimum, anticipate the bill impact of the transition to R-1 and budget accordingly.

Even if the customer has this information, OG&E's proposed demand charge is based on an unforgiving 15-minute interval, which is a very difficult window of time for residential customers to respond within.[64] Doing so requires constant vigilance, which many working families simply lack the time or resources to achieve. Controlling demand effectively also requires technology such as programmable thermostats or load control devices, all of which cost money. OG&E does not intend to offer customers any financial assistance with purchasing or installing such devices as part of the transition to the three-part rate.[65]

Furthermore, once the customer makes a mistake, say by allowing their teenagers to turn on the hairdryer and microwave at the same time the refrigerator and water heater cycle on, their peak demand level is set for the month, removing all further incentive to control demand (even during the system peak hours). If the demand measurement period were longer than 15 minutes, say one hour or an average of a multi-hour system peak window, customers would have some opportunity to correct for these circumstances. The 15-minute measurement interval proposed by OG&E leaves no room for error.

OG&E's failure to present a fully developed educational program or introduce a three-part rate as a pilot exacerbates these problems, but even if OG&E were to address these deficiencies, residential and small commercial customers face significant hurdles in responding to a demand charge. For this reason perhaps, OG&E's proposal to impose default residential demand charges is unprecedented for a utility of its type. Sierra Club therefore urges the Commission to reject OG&E's proposal to introduce any kind of demand charge for residential and small commercial customers.

2. OG&E's Proposed Rate Design is Especially Unfair to Low-Usage and Low-Income Customers

The Company's own data show that low-usage residential customers will pay relatively more under this new rate design, while high-usage customers will experience smaller increases in their bills or even decreases.[66] The amount of revenue recovered from the smallest-usage customers — those consuming an average of 267 kWh per month will increase by over 34%,

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[64] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 18:1-9 ("A shorter demand interval . . . is much harder for a consumer to control"); *see also* Responsive Testimony of Mark Garrett on behalf of TASC, at 24-25.
[65] *See* Attachment Sierra Club-1 (OG&E Response to Sierra Club DR 1-29 ("OG&E has no plans to offer financial assistance to customers in purchasing load control devices such as smart thermostats.")).
[66] *See* Responsive Rate Design Testimony of Kathy J. Champion at 13, Figure 3 (based on AG 1-2 Supplement 3).

while recovery from the highest usage customers (those who use an average of 2,698 kWh monthly) will go down.

These results are not surprising, as high fixed costs shift cost recovery to low-consumption customers as a matter of common sense. When the fixed portion of the bill is increased and the volumetric part of the bill is decreased, the bills of customers with below-average consumption go up, while those of customers who use more than the average amount of electricity will go down.[67] In other words, OG&E's proposal increases recovery from customers who use less electricity, while decreasing the recovery from customers who use more. The Company might contend that low-usage customers underpay for their service under the current tariff, but that argument assumes that the Company's proposed customer charge includes only costs that each customer should properly bear. As discussed by the Attorney General's witnesses, James Daniel and Kevin Mara, the Company's method for allocating costs as "customer-based" sweeps in distribution system costs that are in fact related to demand, and not simply to the number of customers.[68] Mr. Daniel also raises valid concerns about allocating any distribution system costs as customer-related in the absence of a current, valid zero-intercept study.

The Company's position also ignores legitimate reasons why the Commission might prefer a rate design that benefits low-consumption customers, rather than one that lends a helping hand to high-consumption customers. A rate design that favors low-consumption customers incentivizes demand reduction, which reduces costs for everyone on the grid, and provides relief to low-income households.

The increased recovery of revenue from low-usage customers is particularly troubling because low-income households tend to consume less electricity than the average. The most recently available data on electricity consumption and demographics collected by the U.S. Energy Information Administration ("EIA") through the Residential Energy Consumption Survey shows that as gross income rises, so does electricity consumption.[69] These data are helpful in understanding the usage of low-income customers, alongside utility data, which tends to include only those customers who have sought some form of bill payment assistance, and therefore is biased toward higher usage low-income customers.

For the region including Oklahoma, these EIA data reveal that the median annual electricity usage of a household with an income of less than $50,000 is approximately 75% of the usage of higher-income households.[70] Households identified as Asian, Latino, or African-American consumed 14 to 21% less than Caucasian-headed households, while households headed by individuals older than 65 consumed about 15% less electricity than households not

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[67] *See Caught in a Fix, supra* note 2, at 14-15.
[68] *See* Responsive Testimony of James W. Daniel, at 5-8; Responsive Testimony of Kevin J. Mara, at 6-8.
[69] *See Caught in a Fix, supra* note 2, at 15-16 & Figs. 7 & 8.
[70] *See* National Consumer Law Center, Utility Rate Design: How MANDATORY MONTHLY Customer FEES Cause Disproportionate Harm, U.S. REGION: AR, LA, OK (2015), available at http://www.nclc.org/images/pdf/energy_utility_telecom/rate_design/AR-FINAL2.pdf. (Attachment Sierra Club-2). NCLC's source is U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available). As revealed in the Consumers' Union report, this trend holds for all U.S. EIA regions with the exception of a four-state region in the Rocky Mountains. *See Caught n a Fix, supra* note 2, at Figure 7.

headed by these older individuals. Id. Because lower-usage consumers will experience higher bills, on average, these data show that low-income, minority, and elderly households will be harmed by OG&E's proposed rate design change.

In rejecting a fixed charge increase proposed by Xcel Energy, the Minnesota Public Service Commission cited "the need for caution in making any decision that would further burden low income, low usage customers, who are unable to absorb or avoid the increased cost."[71] This Commission should likewise recognize the important public policy of avoiding rate designs that shift the burden of revenue recovery to vulnerable customers.

C. OG&E Offers No Compelling Reason for the Significant Changes to its Default Residential Rates

As explained above, doubling customer charges and imposing a noncoincident peak demand charge will harm OG&E customers by increasing system costs and bills for vulnerable customers. To justify such a rate, OG&E would have to come forward with a compelling reason. However, OG&E's primary justification for the new rate structure is that it better follows cost causation principles.[72] Sierra Club agrees with PUD witness Kathy Champion that cost causation should not dictate rate design—but rather, public policy "considerations such as rate stability, equity and efficiency also play into the design of rates."[73] Cost of service studies are a tool to allocate costs to different jurisdictions and customer classes, but there is no reason why these studies should be the primary criterion for designing rates. Just and reasonable rates should be designed to reflect public policy objectives such as protecting vulnerable customers, and incentivizing desirable behaviors like demand reduction and peak load shaving. Allowing cost-causation to dictate rate design takes away one of the regulator's most powerful tools to shift consumer behavior in ways that reduce costs for all customers.[74]

Furthermore, OG&E's cost-causation rationale founders on the flaws in the underlying cost of service study and in the design of its demand charge. As clearly explained in the testimony of the Attorney General's witnesses James Daniel and Kevin Mara, OG&E's cost of service study inappropriately classifies certain distribution system costs as customer-related.[75] Even if the Commission were to agree that rate design should follow cost causation, it must reject the Company's unsupported and overbroad theory of which costs should be characterized as customer-related.

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[71] Minnesota Public Utilities Commission, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*; Findings of Fact, Conclusions, and Order; Docket No. E-002/GR- 13-868, May 8, 2015, p. 88.

[72] *See* Direct Testimony of Bryan J. Scott on behalf of OG&E, at 4:28-29 (noting that the three-part rate design proposed "accurately recovers the utility's costs to provide electric service"); Direct Testimony of Ahmad Faruqui on behalf of OG&E, at 4 (offering two fundamental reasons to adopt three part rates: that the technology to do so is available and that the three-part rate provides a "more accurate price signal to customers." In response to Sierra Club discovery, OG&E did not provide any further reasons for the rate redesign, such as a failure of the existing rate design to recover adequate revenues. *See* Attachment Sierra Club-1 (OG&E Response to Sierra Club 1-19).

[73] *See* Responsive Rate Design Testimony of Kathy J. Champion at 4:16-5:2 and 5:13-19.

[74] *See id.* at 20:5-6 ("[O]ne advantage to being a bundled utility is that cost recovery can also be bundled and used to achieve the desired signals.").

[75] *See* Responsive Testimony of James W. Daniel, at 5-8; Responsive Testimony of Kevin J. Mara, at 6-8.

Second, the Company's noncoincident demand charge does not reflect cost-causation. The only distribution system cost related to the customer's individual noncoincident peak is the final line transformer.[76] All other transmission and distribution system costs are driven by aggregate customer demands and overall system peaks. A demand charge that recovers demand costs unrelated to the customer's own demand does not recover costs consistent with OG&E's own stated principle.[77]

In sum, OG&E's stated justification for instituting such a radical change in rate design is internally flawed and insufficient to overcome the likely harms to its customers.

IV. The Commission Should Reject OG&E's Proposed Tariffs for Distributed Generation Customers

In this rate case, OG&E continues to seek approval of the discriminatory tariffs for residential and small commercial distributed generation customers for which it has separately sought approval in Cause No. PUD 201500274.[78] The Report and Recommendations of the Administrative Law Judge in that matter, issued December 14, 2015, noted two deficiencies which OG&E was to address in this rate case. First, OG&E was to "completely consider[s] and address] the items on the Commission Staff's Checklist for Distributed Generation Tariff Filings."[79] Second, OG&E was to submit an education plan regarding the proposed DG tariffs, including how they operate and their potential effect. Id.

OG&E has not satisfied either of these requirements. Other than providing an updated cost of service study, OG&E witness Bryan Scott concedes that the Company's rate case application offers no additional information responsive to the checklist beyond that provided in Cause No. PUD 201500274.[80] The neglected checklist items are not trivial or merely procedural. For example, the Commission Staff's Checklist required analysis of the benefits that distributed generation offers the grid, but OG&E's rate case application offers no additional analysis of these benefits. As noted by PUD witness Kathy Champion, failing to consider these benefits can make a significant difference in whether distributed generation resources are cost effective,[81] which is fundamental to the subsidy question underlying 17 O.S. § 156.

OG&E's response to the other deficiency noted by the ALJ—the lack of an education plan—is similarly nonexistent. OG&E witness Bryan Scott states that the Company proposes the same educational plan as previously proposed—direct calls to the fifteen affected DG

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[76] *See* Jim Lazar and Wilson Gonzalez, Smart Rate Design for a Smart Future (July 2015), at 9, available at http://www.raponline.org/document/download/id/7680 ("The only distribution system component sized to individual customer demands is the final line transformer. The relatively small portion of cost of service represented by the line transformer required to serve solar customers amounts to only about $1/ kW/month.").

[77] Rate design can create incentives for customers to shift behaviors in ways that do reduce system costs, such as OG&E's time of use rates and other utilities' inclining block rates, which charge more for higher levels of consumption.

[78] *See* Direct Testimony of Bryan J. Scott, at 14-15.

[79] Cause No. PUD 201500274, Report and Recommendations of the Administrative Law Judge (Dec. 14, 2015), at 22.

[80] *See* Direct Testimony of Bryan J. Scott, at 15:9-14.

[81] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 34:19 to 35:22.

customers[82]—the plan that the ALJ rightly found to be inadequate. OG&E's failure to address the deficiencies highlighted by the ALJ calls for rejecting the Company's proposed tariffs for DG customers.

Even more fatal to OG&E's proposal, however, is that the cost of service study it filed in this case shows that distributed generation customers are not subsidized by OG&E's other customers. To the contrary, residential DG customers are paying more than the cost to serve them.[83] Accordingly, 17 O.S. § 156(B) prohibits any increased rates or surcharge on DG customers.[84] Sierra Club therefore agrees with PUD witness Kathy Champion that any kind of increased fixed charge or demand charge is not justified under S.B 1456.[85] Sierra Club also agrees with the arguments made by TASC witness Mark Garrett regarding the proposed tariffs for distributed generation customers.

V. Conclusion

In conclusion, OG&E's proposal to transform the default rates for residential and general service customers will increase overall system costs and is contrary to state policy. These changes would strip customers of any meaningful degree of control over their electric bills and be especially harmful to low-income customers. The Company's argument that the new rate structure is justified by cost-causation principles rests on a faulty cost of service analysis and a false premise that rate design must reflexively follow cost causation. For these and the aforementioned reasons, OG&E's proposed changes to the default tariffs for residential and general service customers, and its proposed tariffs for distribution generation customers, should be denied.

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[82] *See* Direct Testimony of Bryan J. Scott, at 15:16-19.
[83] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 32:15-18.
[84] 17 O.S. § 156(B) ("No retail electric supplier shall increase rates charged or enforce a surcharge above that required to recover the full costs necessary to serve customers who install distributed generation . . ."
[85] *See* Responsive Rate Design Testimony of Kathy J. Champion, at 33:13 to 34:12.

Appendix "B"

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OF OKLAHOMA	))))))	CAUSE NO. PUD 201500273

JOINT STIPULATION AND SETTLEMENT AGREEMENT AS TO CERTAIN RATE DESIGN, COST OF SERVICE, AND FUEL ADJUSTMENT ISSUES

COME NOW the undersigned parties to the above entitled Cause and pursuant to 17 O.S. § 282 present the following Joint Stipulation and Settlement Agreement on Certain Rate Design, Cost of Service, and Fuel Adjustment Clause Issues ("Joint Stipulation") for the review and consideration of the Oklahoma Corporation Commission ("Commission") as their compromise and settlement of certain rate design, cost of service, and Fuel Adjustment Clause issues in this proceeding between the parties to this Joint Stipulation ("Stipulating Parties").

The Stipulating Parties are: **Public Utility Division, Oklahoma Corporation Commission; Attorney General of the State of Oklahoma; Oklahoma Industrial Energy Consumers; Wal-Mart Stores East, LP and Sam's East, Inc.; AARP; Oklahoma Sustainability Network; The Alliance for Solar Choice; The Oklahoma Hospital Association; The Wind Coalition; Oklahoma Energy Results, LLC; Federal Executive Agencies; Sierra Club and Citizen Potawatomi Nation.**

The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of the rate design, cost allocation, and Fuel Adjustment Clause issues addressed herein, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

This Stipulating Parties note these rate design. cost allocation. and Fuel Adjustment Clause issues are revenue neutral to the Company: they address only how revenue recovery is allocated among the various customer classes. and how the rates for each class are designed to recover that revenue. Therefore. and because a variety of customer classes are represented among the Stipulating Parties, along with all other parties to this matter other than Oklahoma Gas and Electric Company ("OG&E" or the "Company") and its Shareholders' Association. it is fair and reasonable for the Commission to accept the resolution of these matters as set forth below.

Terms of the Joint Stipulation and Settlement Agreement
Regarding Certain Rate Design, Cost of Service, and Fuel Adjustment Clause Issues

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

Effective with the final order of the Commission approving all elements of this Joint Stipulation:

1. **No New Demand Charges.**

a. No new demand charge shall be implemented for any customer class or sub class not currently paying a demand charge.

b. Before proposing the introduction of any new demand charges. OG&E will be required to provide a cost of service study of low. medium. and high energy users within major rate classes not currently containing a demand charge.

c. Before proposing the introduction of any new demand charges for any rate class. not currently subject to a demand charge, OG&E will conduct a pilot program on demand charges to evaluate customer acceptance. understanding. and ability to respond to a rate design that includes

demand charges. OG&E will also be required to provide bill impact analysis for participating low, medium, and high energy users.

2. **Monthly Customer Charge.**

a. The Monthly Customer Charge for Residential, General Service, and Public School rate classes shall remain at current levels.

3. **Distributed Generation Customers – Residential and Small Commercial.**

a. Standard pricing schedules available to distributed generation customers, as of the date of approval of this Joint Stipulation, shall continue to be available to all distributed generation customers until the next general rate case review. Distributed generation customers who use some of their output to serve onsite load will take service on the standard TOU rates.

b. No customer with distributed generation shall be required to take service on a standard pricing schedule with a demand charge component as a condition of installing and operating distributed generation facilities.

c. Customers with distributed generation facilities that sell all output to OG&E (and do not use any portion of the output of the system to serve onsite load) may take service on any tariff available to customers in the class to which the customer would belong without the installation of distributed generation.

d. In the event OG&E proposes, in the future, a demand charge or any other substantive change to a tariff applicable to customers with distributed generation, which the Company deems necessary to comply with 17 O.S. § 156, OG&E shall be required to hire an independent third party to perform a benefit analysis of distributed generation production.

e. The Stipulating Parties intend that the provisions of this Section 3 comply with the requirements of 17 O.S. § 156.

4. **Revenue Allocation.**

a. The Stipulating Parties agree to utilize the OG&E Cost of Service Study except as otherwise provided for within this Joint Stipulation.

b. If the Commission shall determine that a base rate revenue reduction is warranted, then the allocations shall occur as follows:

i. The revenue requirement decrease determined by the Commission will be distributed to the customer rate classes using the stepped iterative approach below:

1. In Step 1, the base rate revenue reduction will first be allocated proportionally to the rate classes with a relative rate of return ("RROR") greater than 1. No rate class with an RROR below 1 will receive an increase in this step.

2. In Step 2, rate classes with an RROR less than 1 will move to an RROR of 1. Revenues from this step will be redistributed proportionally to the classes with an RROR greater than 1. Public Schools, Municipal Lighting, and Residential will not receive an increase.

3. The Large Power and Light ("LPL") Service levels 1 through 4 revenue decrease resulting from Steps 1 and 2 above will be distributed on an equal percentage basis to LPL Service Levels 1 through 4.

4. In Step 3, any revenue decrease not yet distributed pursuant to Steps 1 and 2 above will be used to reduce residential class rates.

ii. The effect of this stepped approach will be to ensure that the Residential, Public School, and Municipal Lighting classes do not receive a rate increase in the event a base rate revenue decrease is ordered. In addition, the classes other than Residential, Public School, and Municipal Lighting, with a current RROR of less than 1, will move closer toward a RROR of 1.

iii. An illustration of this approach is provided in Attachment 1, Subpart A.

c. If the Commission shall determine that a base rate increase is warranted, the allocations shall occur as follows:

i. Any revenue requirement increase determined by the Commission will be distributed to the customer rate classes using the stepped iterative approach below:

1. In Step 1, all rate classes with a current RROR below 1 will move 25 percent of the way toward an RROR of 1. The revenue increases associated with this movement will be redistributed proportionally to rate classes with an RROR greater than 1 as revenue decreases. Public Schools will not receive any additional increase in subsequent steps.

2. In Step 2, all General Service, Power and Light, and LPL rate classes with an RROR less than 1 will move the remaining 75 percent of the way to an RROR of 1. The amount eliminated in this step will be redistributed proportionally to the General Service, Power and Light, Oil and Gas Production, and LPL classes with an RROR greater than 1.

3. In Step 3, any revenue increase or decrease distributed to the LPL Service levels 1 through 4 pursuant to Steps 1 and 2 above will be

distributed on an equal percentage basis to LPL Service Levels 1 through 4.

ii. The effect of this stepped approach will be to move the classes that have a current RROR of less than 1.25% closer to an RROR of 1, except that General Service, Power and Light and LPL classes with an RROR of less than 1 will move 100% of the way to an RROR of 1.

iii. An illustration of this approach is provided in Attachment 1, Subpart B.

5. **Miscellaneous Charges.**

a. Service Initiation Fee: The Service Initiation Fee will be $17.50;

b. Reconnection Charge: The Reconnection Charge will be $21.00; and

c. Meter Test Fee: The Meter Test Fee will be $75.00.

6. **PayGo Prepay Billing Option.**

a. Tariff modifications will be made to include more program details and customer protections as set forth in Attachment 2.

b. Reporting: OG&E shall, at a minimum, track and report the following information to the Public Utility Division and Office of the Attorney General on an annual basis:

i. Program costs and savings to OG&E by month, including but not limited to, PayGo's impact on OG&E's bad debt;

ii. Frequency and duration of PayGo disconnections by month, which will include additional explanation of any reconnections taking longer than 15 minutes;

iii. Total customer participation in PayGo by class and rate tariff by month: and

iv. Total number of customers on PayGo who, according to OG&E's records, and to the extent available, have received financial assistance with their utility bills within one (1) year of enrolling in PayGo, including customers who receive assistance through OG&E's Low Income Assistance Program Rider.

c. Customer Acknowledgement: OG&E shall obtain a customer's acknowledgement of the following information prior to the customer's enrollment in PayGo:

> To continue to receive service under PayGo, you must pre-pay for service and maintain a positive account balance. If your balance falls to $0.00, your service will be disconnected. You will receive notice of disconnection by email or text depending on the communication method you select when enrolling in PayGo. Notice of disconnection will not be posted at your home or sent through the mail. You may switch back to standard billing at any time without penalty by contacting an OG&E service representative.

7. **Automated Metering Opt Out Tariff.**

a. Automated Metering Opt Out Tariff, as requested in the Application in this Cause, will be implemented.

8. **Zero Intercept Study.**

a. OG&E shall conduct an updated Zero Intercept Study and provide such study and the results to all parties as a part of its next rate case.

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9. **PL-TOU Rate Design.**

a. The resulting base rate revenue reduction from moving other classes with an RROR of less than 1. as per Section (4) above. shall be applied to each of the Power and Light-TOU rate schedule service levels and shall be applied first to the respective winter and off-peak summer energy charges for each service level, until those rates are equal but not less than the comparable LPL-TOU rates.

b. Any additional change to the Power and Light-TOU service level revenue requirements shall be applied on an equal percentage basis to all Power and Light-TOU charges within that service level.

10. **LPL-TOU Rate Design.**

a. The higher demand charges proposed by OG&E for LPL Service Levels 2-5 shall be implemented and will be adjusted upward or downward by the percentage change in revenues that results from the revenue allocation set forth in Section (4) above.

b. The current demand charge spread of $0.60/kW between LPL Service Level 1 and LPL Service Level 2 shall be maintained. The base Summer On-Peak kWh charge as proposed by OG&E will be equalized for LPL 1 and LPL 2 and energy charges for LPL 1 and LPL 2 will continue to be the same.

11. **Fuel Adjustment Clause ("FAC").**

a. The Parties understand that OG&E's April 2016 fuel submission had a fuel balance of approximately $55 million. The Company will adjust the FAC factors to return to. or collect

from. customers any over or under recovery fuel balance that exists at the time new rates are implemented pursuant to this Cause. The fuel adjustment clause overage or underage, which the Company has over or under collected from its customer classes. as of the date of the Commission issuance of an Order approving this Stipulation. shall be credited back to. or collected from. the Company's customer classes beginning 30 days after the effective date of such Order and continuing monthly for 12 consecutive months. on the same basis that such fuel costs were collected. until such overage or underage has been fully credited to. or collected from. the Company's customer classes.

12. **General Reservations.**

The Stipulating Parties represent and agree that. except as specifically otherwise provided herein:

a. This Joint Stipulation represents a negotiated settlement for the purpose of compromising and settling the above-described rate design. cost of service. and Fuel Adjustment Clause issues. which were raised in this proceeding.

b. Each of the undersigned counsel of record affirmatively represents to the Commission that he or she has fully advised their respective client(s) that the execution of this Joint Stipulation constitutes a resolution of cost of service. rate design. and Fuel Adjustment Clause issues set forth herein: that no promise. inducement or agreement not herein expressed has been made to any party to this Joint Stipulation; that this Joint Stipulation constitutes the entire agreement between and among the Stipulating Parties with respect to cost of service. rate design. and Fuel Adjustment Clause issues; and each of the undersigned counsel of record affirmatively

represents that he or she has full authority to execute this Joint Stipulation on behalf of his or her client(s).

c. None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation.

d. None of the signatories hereto shall be deemed to have approved or acquiesced in any cost of service determination, cost allocation method or rate design proposal underlying or allegedly underlying any of the rate schedules to be filed by OG&E upon approval by the Commission of this Joint Stipulation, and nothing contained herein shall constitute an admission by any party that any allegation or contention in this proceedings regarding cost of service or rate design, or as to any of the foregoing matters, is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made therewith in this rate proceeding.

e. The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, have entered into this Joint Stipulation to resolve among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its

position or testimony in other causes. To the extent there is a difference. the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement. the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

13. **Non Severability.**

The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore. in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (unless the affected party or parties may consent to such modification or condition). this Joint Stipulation shall be void and of no force and effect. and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation.

WHEREFORE. the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement of this proceeding with respect to the certain cost of service. rate design. and Fuel Adjustment Clause issues which were raised with respect to Application filed by Oklahoma Gas & Electric Company and are

specifically set forth and addressed in the Joint Stipulation and Settlement Agreement, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement on rate design, cost of service, and Fuel Adjustment Clause.

14. **Counterparts.**

This Joint Stipulation may be executed in any number of counterparts, each of which shall be considered an original for all purposes.

PUBLIC UTILITY DIVISION, OKLAHOMA CORPORATION COMMISSION

By: Fairo Mitchell Date: 5/23/16
Fairo Mitchell, Energy and Water Policy Director, Oklahoma Corporation Commission

E. SCOTT PRUITT, ATTORNEY GENERAL OF THE STATE OF OKLAHOMA

By: Dara Derryberry Date: 5/23/16
~~Mike Hunter, First~~ Assistant Attorney General, Office of the Oklahoma Attorney General
Dara Derryberry

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: Date: 5/23/16
Thomas P. Schroedter, Attorney, Hall, Estill, Hardwick, Gable, Golden & Nelson

WAL-MART STORES EAST, LP AND SAM'S EAST, INC.

By: Date: 5/23/16
Rick D. Chamberlain, Attorney, Behrens, Wheeler & Chamberlain

AARP

By: Deborah R Thompson Date: 5/23/16
Deborah R. Thompson, Attorney, OK Energy Firm, PLLC

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OKLAHOMA SUSTAINABILITY NETWORK

By: Deborah R Thompson Date: 5/23/16
Deborah R. Thompson, Attorney, OK Energy Firm, PLLC

FEDERAL EXECUTIVE AGENCIES

By: _____ Date: _____
Thomas A. Jernigan, USAF, AFCEC/JA-ULFSC

THE ALLIANCE FOR SOLAR CHOICE

By: Marc Edwards Date: 5/23/16
Jim Roth, Attorney, Phillips Murrah

OKLAHOMA HOSPITAL ASSOCIATION

By: Marc Edwards Date: 5/23/16
Jim Roth, Attorney, Phillips Murrah

THE WIND COALITION

By: Marc Edwards Date: 5/23/16
Jim Roth, Attorney, Phillips Murrah

OKLAHOMA ENERGY RESULTS, LLC

By: Cheryl A Vaught Date: 5-23-16
Cheryl A. Vaught, Attorney, Vaught & Conner, PLLC

SIERRA CLUB

By: Jacquelyn L. Dill Date: 5/23/16
Jacquelyn L. Dill, Attorney, The Dill Law Firm

Joint Stipulation
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CITIZEN POTAWATOMI NATION

By: Lee W. Paden Date: May 23, 2016
Lee W. Paden, Attorney, Law Offices of Lee W. Paden, P.C.

PUBLIC UTILITY DIVISION, OKLAHOMA CORPORATION COMMISSION

By: _____ Date: _____
Fairo Mitchell, Energy and Water Policy Director, Oklahoma Corporation Commission

E. SCOTT PRUITT, ATTORNEY GENERAL OF THE STATE OF OKLAHOMA

By: _____ Date: _____
Mike Hunter, First Assistant Attorney General, Office of the Oklahoma Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

By: _____ Date: _____
Thomas P. Schroedter, Attorney, Hall, Estill, Hardwick, Gable, Golden & Nelson

WAL-MART STORES EAST, LP AND SAM'S EAST, INC.

By: _____ Date: _____
Rick D. Chamberlain, Attorney, Behrens, Wheeler & Chamberlain

AARP

By: _____ Date: _____
Deborah R. Thompson, Attorney, OK Energy Firm, PLLC

OKLAHOMA SUSTAINABILITY NETWORK

By: _____ Date: _____
Deborah R. Thompson, Attorney, OK Energy Firm, PLLC

FEDERAL EXECUTIVE AGENCIES

By: _____ Date: 23 May 16
Thomas A. Jernigan, USAF, AFCEC/JA-ULFSC

THE ALLIANCE FOR SOLAR CHOICE

By: _____ Date: _____
Jim Roth, Attorney, Phillips Murrah

OKLAHOMA GAS & ELECTRIC COMPANY
Test Year Ended 6-30-15
Cause No. PUD 201500273

Calculations for Illustrative Purposes Only
Intervener Revenue Distribution Settlement Proposal
May 23, 2016

Ln	A Rate Class	B Distribute Revenue At Equalized RROR	C Eliminate 25% of RROR Below 1	D Redistribute to Classes With RROR Above 1	E Step 1 Results	F Eliminate 100% of RROR below 1 GS, PL, & LPL	G Redistribute to RROR Above 1 Classes	H Step 2 Results	I Step 3 Results	J RROR % Eliminated	K Settlement Rate Change w/o FCA	L OGE Proposed Change [W/P M-4]	M Distribute FAC Balance to Classes ($55,000,000)	N Total Decrease from Settlement
1	RS	$28,628,027	$21,471,020		$7,157,007			$7,157,007	$7,157,007	25%	0.85%	6.60%	(19,211,693)	(12,054,686)
2	GS	$9,074,297	$6,805,723		$2,268,574	$6,805,723		$9,074,297	$9,074,297	100%	6.49%	12.60%	(2,894,807)	6,179,491
3	GS TOU	($883,885)		($801,025)	($82,860)		($261,541)	($344,401)	($344,401)	39%	1.62%	0.00%	($67,817)	(912,213)
4	SCH	$5,175,688	$3,881,766		$1,293,922			$1,293,922	$1,293,922	25%	6.73%	5.60%	(566,639)	727,283
5	SCH DMD	$1,691,760	$1,268,820		$422,940			$422,940	$422,940	25%	3.17%	6.90%	(419,084)	3,856
6	OGP	($4,155,944)		($3,766,343)	($389,601)		($1,229,739)	($1,619,341)	($1,619,341)	39%	-7.67%	0.00%	(672,021)	(2,291,362)
7	PL1	($41,679)		($37,772)	($3,907)		($12,333)	($16,240)	($16,240)	39%	-12.06%	-5.12%	(5,076)	(21,316)
8	PL2	($258,293)		($234,079)	($24,214)		($76,429)	($100,642)	($100,642)	39%	-8.44%	-1.54%	(30,659)	(131,301)
9	PL3	($4,422,291)		($4,007,721)	($414,570)		($1,308,551)	($1,723,121)	($1,723,121)	39%	-8.09%	-2.15%	(782,431)	(2,505,552)
10	PL4	($1,067,897)		($967,787)	($100,111)		($315,990)	($416,100)	($416,100)	39%	-6.39%	-2.60%	(226,798)	(642,899)
11	PLS	$6,575,051	$4,931,288		$1,643,763	$4,931,288		$6,575,051	$6,575,051	100%	2.64%	7.11%	(7,610,333)	(1,035,282)
12	PL TOU 1	($676,649)		($613,216)	($63,433)		($200,220)	($263,653)	($263,653)	39%	-13.40%	-1.27%	(45,135)	(308,787)
13	PL TOU 2	($659,515)		($597,688)	($61,827)		($195,150)	($256,976)	($256,976)	39%	-8.51%	-2.24%	(105,330)	(362,306)
14	PL TOU 3	($7,736,281)		($7,011,039)	($725,242)		($2,289,157)	($3,014,399)	($3,014,399)	39%	-8.65%	-2.16%	(1,300,721)	(4,315,120)
15	PL TOU 4	($1,408,319)		($1,276,295)	($132,024)		($416,720)	($548,744)	($548,744)	39%	-4.86%	-2.57%	(389,937)	(938,680)
16	PL TOU 5	($4,243,766)		($3,845,932)	($397,834)		($1,255,726)	($1,653,560)	($1,653,560)	39%	-1.11%	0.77%	(4,992,207)	(6,645,767)
17	LPL 1	($921,251)		($834,888)	($86,363)		($272,597)	($358,960)	($948,005)	103%	-3.02%	0.25%	(1,614,640)	(2,562,645)
18	LPL 2	($14,850,560)		($13,458,386)	($1,392,174)		($4,394,265)	($5,786,438)	($5,697,786)	38%	-3.02%	-2.83%	(9,200,375)	(14,898,762)
19	LPL 3	($4,757,176)		($4,311,212)	($445,964)		($1,407,643)	($1,853,607)	($1,421,875)	30%	-3.02%	-2.54%	(2,071,522)	(3,493,397)
20	LPL 4	($1,284,731)		($1,164,293)	($120,438)		($380,150)	($500,588)	($431,929)	34%	3.02%	3.42%	(594,277)	(1,026,206)
21	LPL 5	$2,982,834	$2,237,125		$745,708	$2,237,125		$2,982,834	$2,982,834	100%	12.18%	7.78%	(945,672)	2,037,162
22	MUN PMP	($869,677)		($788,149)	($81,528)		($257,337)	($338,865)	($338,865)	39%	-3.96%	-0.35%	(298,543)	(637,408)
23	MUN LGT	$3,760,894	$2,820,671		$940,224			$940,224	$940,224	25%	6.50%	10.50%	(203,628)	736,595
24	SEC LGT	$399,215	$299,411		$99,804	$299,411		$399,215	$399,215	100%	1.96%	3.80%	(250,060)	149,155
		$10,049,853	$43,715,825	-$43,715,825	$10,049,853	$14,273,548	-$14,273,548	$10,049,853	$10,049,853		0.5%	4.90%	(55,000,000)	(44,950,147)

RS Increase:	$0.90 / Month

OKLAHOMA GAS & ELECTRIC COMPANY

Test Year Ended 6-30-15
Cause No. PUD 201500273

Calculations for Illustrative Purposes Only
Intervener Revenue Distribution Settlement Proposal
May 23, 2016

Ln	A Rate Class	B Distribute Revenues At Equalized RROR $10M Decrease	C Eliminate Increase to Any Class	D Redistribute to Classes with RROR Below 1	E Step 1 Results	F Eliminate Below RROR $ GS, PL, & LPL	G Redistribute to Above RROR Classes	H Step 2 Results	I Step 3 Results	J RROR % Eliminated	K Settlement Rate Change w/o FCA	L OGE Proposed Change [W/P M-4]	M Distribute FAC Balance to Classes ($55,000,000)	N Total Decrease from Settlement
1	RS	$18,724,687	$18,724,687		$0			$0	$0	0%	0.00%	6.60%	(19,211,693)	(19,211,693)
2	GS	$7,217,135	$7,217,135		$0	7,217,135		$7,217,135	$7,217,135	100%	5.16%	12.60%	(2,894,807)	4,322,328
3	GS TOU	($1,099,831)		($889,469)	($210,362)		($289,544)	($499,906)	($499,906)	45%	-2.35%	0.00%	(567,812)	(1,067,719)
4	SCH	$4,849,014	$4,849,014		$0			$0	$0	0%	0.00%	5.60%	(566,639)	(566,639)
5	SCH DMD	$1,513,011	$1,513,011		$0			$0	$0	0%	0.00%	6.90%	(419,084)	(419,084)
6	OGP	($4,301,231)		($3,478,545)	($822,686)		($1,132,352)	($1,955,039)	($1,955,039)	45%	-9.26%	0.00%	(672,021)	(2,627,060)
7	PL1	($42,241)		($34,162)	($8,079)		($11,120)	($19,200)	($19,200)	45%	-14.26%	-5.12%	(5,076)	(24,275)
8	PL2	($270,969)		($219,141)	($51,828)		($71,336)	($123,164)	($123,164)	45%	-10.33%	-1.54%	(30,659)	(153,822)
9	PL3	($4,559,367)		($3,687,308)	($872,060)		($1,200,310)	($2,072,369)	($2,072,369)	45%	-9.73%	-2.15%	(782,431)	(2,854,800)
10	PL4	($1,113,259)		($900,329)	($212,931)		($293,079)	($506,010)	($506,010)	45%	-7.78%	-2.60%	(226,798)	(732,808)
11	PLS	$3,781,080	$3,781,080		$0	3,781,080		$3,781,080	$3,781,080	100%	1.52%	7.11%	(7,610,333)	(3,829,252)
12	PL TOU 1	($689,214)		($557,390)	($131,824)		($181,444)	($313,269)	($313,269)	45%	-15.92%	-1.27%	(45,135)	(358,403)
13	PL TOU 2	($680,807)		($550,590)	($130,216)		($179,231)	($309,447)	($309,447)	45%	-10.24%	-2.24%	(105,330)	(414,777)
14	PL TOU 3	($7,948,396)		($6,428,125)	($1,520,271)		($2,092,514)	($3,612,785)	($3,612,785)	45%	-10.37%	-2.16%	(1,300,721)	(4,913,505)
15	PL TOU 4	($1,494,804)		($1,208,896)	($285,908)		($393,526)	($679,433)	($679,433)	45%	-6.02%	-7.57%	(389,937)	(1,069,370)
16	PL TOU 5	($5,634,419)		($4,556,737)	($1,077,682)		($1,483,331)	($2,561,013)	($2,561,013)	45%	-1.72%	0.77%	(4,992,207)	(7,553,219)
17	LPL 1	($1,137,029)		($919,552)	($217,477)		($299,337)	($516,814)	**(1,199,433)**	105%	-3.82%	0.25%	(1,614,640)	(2,814,073)
18	LPL 2	($16,057,497)		($12,986,217)	($3,071,280)		($4,227,335)	($7,298,615)	**(7,208,941)**	45%	-3.82%	-2.83%	(9,200,975)	(16,409,916)
19	LPL 3	($5,084,027)		($4,111,617)	($972,410)		($1,338,433)	($2,310,843)	**(1,798,981)**	35%	-3.82%	-2.54%	(2,071,522)	(3,870,503)
20	LPL 4	($1,380,694)		($1,116,612)	($264,082)		($363,485)	($627,567)	**(546,484)**	40%	-3.82%	-3.42%	(594,277)	(1,140,762)
21	LPL 5	$2,686,380	$2,686,380		$0	2,686,380		$2,686,380	$2,686,380	100%	10.97%	7.78%	(945,672)	1,740,708
22	MUN PMP	($936,518)		($757,392)	($179,126)		($246,550)	($425,675)	($425,675)	45%	-4.98%	-0.35%	(298,543)	(724,219)
23	MUN LGT	$3,512,442	$3,512,442		$0			$0	$0	0%	0.00%	10.50%	(203,628)	(203,628)
24	SEC LGT	$118,333	$118,333		$0	118,333		$118,333	$118,333	100%	0.58%	3.80%	(250,060)	(131,727)
		-$10,028,221	$42,402,081	-$42,402,081	-$10,028,221	$13,802,927	-$13,802,927	-$10,028,221	-$10,028,221		-0.5%	4.90%	(55,000,000)	(65,028,221)

RS Increase:	$0.00 / Month

Exhibit 2

Joint Stipulation and Settlement
Rate Design and Cost of Service
Cause No. PUD 2015-273

PayGo Provisions

1. **Modifications to Section 220 of Oklahoma Gas & Electric Company's ("OG&E's") Terms and Conditions of Service Tariff.**

The following provisions shall be added and included in Section 220 of OG&E's Terms and Conditions of Service Tariff:

220 RESIDENTIAL CUSTOMER PREPAY ("PayGo") BILL PROVISION

Eligibility:

Residential customers who are taking service where the supporting technology and infrastructure are available may request to participate in the PayGo Bill program. Additional fees, including reconnect and disconnect, will not be charged to customers except where required by third-party pay agents and security deposits will not be required.

Customers residing at duplexes or apartment houses that are served under one meter are excluded from participating in the PayGo Bill program. Customers with medical necessities for service are prohibited from participation. Customers choosing to participate in the Prepay Bill program are excluded from subscribing to the Net Energy Billing Option of the Standard Purchase Agreement, to the Green Power Wind Rider, and the Community Solar Program. Customers will not have the option of the AMB payment plan.

Program Terms:

1. The customer's standard rates will apply, prorated to a daily basis when necessary.
2. A customer with an outstanding balance may enroll in PayGo by paying 50% of his outstanding balance. Thereafter, any payments made on the customer's PayGo account shall be applied 20% to the outstanding balance and 80% toward electric service.
3. To enroll in PayGo a customer must establish an initial account balance of $25.00.
4. Zero or negative balance will result in an automatic disconnection. Disconnects scheduled to occur during weather moratoriums, after 5 p.m. on weekdays, on Saturday or Sunday will not be disconnected and instead rescheduled for the next business day. Customers will not be disconnected on Company-observed holidays.
5. Customers can re-activate electric service by adding funds to their account.
6. OG&E shall notify a customer via his selected notification method prior to disconnection. Customers have the option to select a preferred manner of notification and at what balance level notifications shall occur, but in any event, a customer will receive an initial notification when his account reaches a minimum threshold amount of $20.00.

7. No late fee charges shall apply to customers enrolled in PayGo.
8. Under this provision OG&E will not leave a paper copy of the notice of disconnection at the premise. The following provisions shall not apply to service provided pursuant to PayGo: OAC 165:35-21-10(d) and (e); OAC 165:35-21-11; OAC 165:35-21-20(a), (b), (c), and (d); and OAC 165:35-21-21.
9. PayGo customers shall have the same ability to make payments twenty-four (24) hours per day as they would under Standard billing including: over the phone, online, and via third party kiosks.
10. Customers may exit at any time with no exist fee and all standard terms and conditions will then apply.
    i. Any credit balance on the customer's account shall be credited against the customer's next month's bill. If the customer is leaving the OG&E system, the refund shall be sent to the customer within thirty (30) days.
    ii. If the customer has an arrearage balance and has not defaulted on a pay arrangement within the last twelve (12) months, a new pay arrangement to assist the customer will be implemented if requested.
    iii. Customers who wish to switch from PayGo to standard post-pay billing will be permitted to do so regardless of whether or not the customer has paid his remaining arrearage balance.

Appendix C

OKLAHOMA GAS & ELECTRIC COMPANY
Summary of Party Recommended Adjustments
Cause No. PUD 201500273
Test Year Ended June 30, 2015

OG&E Requested Increase of $92,494,692
Based on ROE of 10.25% on 53.31% Equity

Party	PUD	AG	OIEC/OEP	FEA	CPN	AARP	OG&E
Rate Base Adjustment	92,494,692	92,494,692 (272,421) 92,222,271	92,494,692				92,494,692
Plant In Service	1,440,535	1,440,537	1,440,487				1,440,809
Accumulated Depreciation	3,330,648	3,330,651	3,330,536				3,330,916
Plant Held For Future Use	22,769	(124,637)	(124,633)				24,636
Accumulated Deferred Income Tax		84,797	84,794				84,797
Customer Deposits	(132,673)	(132,671)	(132,667)				(132,673)
Fuel Inventories	2,055,900						
Gas in Storage	89,648						
Asset Retirement Obligations		(403,118)	(403,104)				(403,118)
Materials and Supplies	(92,326)	(92,323)	(92,320)				(92,403)
Prepayments	9,176	9,176	9,175				9,176
Net Pension Benefit Asset		(744,545)	(744,562)				(744,545)
Cash Working Capital	(118,844)						(118,733)
Gain on Sale of Assets		(131,233)	(109,051)				
Total Rate Base Adjustments	6,604,833	3,236,634	3,258,656				3,398,862
Adjusted Rate Base	4,209,521,090	4,180,555,597	4,180,547,270		Did Not List Adjustments		4,200,344,953
Adjust Capital Structure	53.31% Equity	50% Equity	53.31% Equity	53.31% Equity	53.31% Equity		53.31% Equity
Return On Equity	9.25%	9.25%	9.0%	9.30%	9.0%	Not greater than 9.25%	10.25%
Adjust for Cap Structure		(15,387,889)					
Adjust for ROE	(37,170,071)	(34,136,784)	(45,476,468)				
Cost of Debt	5.62%	5.62%	5.62%	5.62%	5.62%		5.62%
Rate of Return	7.58%	7.44%	7.42%	7.58%	7.42%		8.08%

Party	PUD	AG	OIEC/OER	FEA	CPN	AARP	OG&E
Revenue and Expense Adjustment							
Adjust Revenue For Customer Growth		(5,375,062)	(5,375,062)				(5,375,062)
Gain on Sale of Utility Assets		(573,978)	(591,808)				(32,085)[7]
Customer Deposit Interest	16,767						16,749
Payroll annualized at 12/31/15	(2,477,123)	(5,097,319)	(5,097,319)				(486,681)
Payroll Taxes Annualized at 12/31/15	(164,817)	(357,881)	(357,881)				(34,165)
Power Generation	(245,341)						
Bad Debt	(25,352)						(25,222)
Remove 50% Short-term Incentive	Allow 100%	(7,104,635)	(7,104,554)				Allow 100%
Remove 50% payroll taxes on Incentives	Allow 100%	(498,745)	(498,740)				Allow 100%
Remove long-term Incentives	(4,135,302)[8]	(5,505,684)	(5,505,652)				Allow 100%
Dues and Donations	(106,535)		(106,535)				
Remove Supplement Executive Retirement	(1,713,195)	(1,713,195)	(1,713,195)				(1,713,195)
Advertising	(494,684)		(494,684)				
Reverse Affiliate		(5,579,128)	(5,579,128)				(1,951,377)
Reverse OG&E Ad Valorem	(4,166,714)	(4,166,889)	(4,166,889)				No change
Outside Services	(184,201)						(272,125)
Production Tax Credit	(3,676,868)						
OK Jurisdictional Adjustment	(162,811)						
Limit Vegetation management Cycle Expense	(5,394,895)[9]	(4,454,171)	(5,983,404)[9]				
Reduce Non-Cycle Trim Expense	Included in above	(657,627)	Included in above				
Depreciation Expense	(33,014,321)	(33,014,321)	(37,298,897)	(44,820,448)			
Smart Meters			(3,679,140)				
Rate Case Expense							(194,572)
Regulatory Expense			(365,317)				(172,878)
Exclude witness training	(299,399)	(75,000)					
Exclude Shareholder Legal Expense	(421,287)	(665,651)[1]					

PARTY	PUD	AG	OIEC/OER	FEA	CPN	AARP	OG&E
Revenue Adjustment	**(56,066,270)**	**121,026,725)**	**(126,136,021)**				**(10,242,614)**
Increase/Decrease	**5,863,184**	**(28,804,454)**	**(33,641,329)**				**35,650,948**
Added PUD's Distribution Deprec.			(15,183,337)				
			(48,824,666)				
OER files separate proposed order			(571,185)				
reducing OG&E needed transmission revenue			**(49,395,851)**				

Table 2 below summarizes the recommendations of the ALJ.

SUMMARY OF ALJ RECOMMENDATION
Cause No.201500273
Test Year Ended June 30, 2015

	ALJ
Rate Base	$4,152.329.406
Adjusted Rate Base	$4,198,347,364
Relative Rate of Return (RROR)	7.88%
Adjusted Operating Expense (Including Depreciation)	$801,945,164
Adjusted Income Tax	$77,651,086
Adjusted Revenue Requirement	$1,210,677,923
Increase/(Decrease)	$60,303,384

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	)	CAUSE NO. PUD 201500273

ERRATA
Appendix C Page 285

When the Administrative Law Judge's (ALJ) recommendations in PUD 201500273 were run through the accounting process an incorrect total was inadvertently reported.

It is important to note the numbers below **do not** reflect any changes to the adjustments laid out in the ALJ report. They simply reflect the corrected application of the ALJ's proposals.

SUMMARY OF ALJ RECOMMENDATION
Cause No.201500273
Test Year Ended June 30, 2015

	OG&E	ALJ	
Rate Base	$4,152,329,406	$4,152,329,406	
Adjusted Rate Base	$4,200,344,953	~~$4,198,347,364~~	$4,199,301,945
Relative Rate of Return (RROR)	8.088%	7.88%	
Adjusted Operating Expense (Including Depreciation)	($10,242,614)	~~$801,945,164~~	$791,193,770
Adjusted Income Tax		~~$77,651,086~~	$74,122,822
Adjusted Revenue Requirement	$1,289,048,372	~~$1,210,677,923~~	$1,196,473,543
Increase/(Decrease)	$85,650,940	~~$60,303,384~~	$40,723,942

*The errata change adjusts the Cash Working Capital to $(21,862,040)
**The errata change adjusts the current income tax expense (labeled as interest sync in the ALJ report)-$1,378,707
***The same chart appears on Page 85 where the same corrections should be made.

Respectfully submitted,

BEN JACKSON
Administrative Law Judge

12/16/16
Date