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JAN 04 2017
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CORPORATION COMMISSION
OF OKLAHOMA

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)

**EXCEPTIONS TO THE REPORT OF THE ADMINISTRATIVE LAW JUDGE OF
OKLAHOMA GAS AND ELECTRIC COMPANY**

In accordance with OAC 165:5-13-5, Oklahoma Gas and Electric Company (“OG&E”) hereby files these exceptions to the Report and Recommendations of the Administrative Law Judge (“ALJ Report”) issued in this cause on December 8, 2016, and modified by an Errata to Appendix C filed on December 16, 2016. OG&E respectfully asks that the Commission adopt the ALJ Report with certain amendments as identified herein.

I. INTRODUCTION

OG&E first expresses its appreciation to the Administrative Law Judge (“ALJ”), the Commissioners, and the Commissioners’ aides for their participation and attention to this Cause, which is of great importance to OG&E and stakeholders alike. A rate case requires an in-depth examination of a utility’s expenses and revenues within a defined timeframe. A review of this breadth and scope typically involves a great many hours of labor and expense culminating in a hearing that is generally lengthy and contentious. In this particular Cause, over a dozen parties participated in a hearing that lasted nearly a month and a vast amount of information concerning numerous issues was provided by the parties with many differing positions stated. The consideration and resolution of the many issues requires extensive research, analysis, and thought by all involved in the review of this Cause.

OG&E observes that the ALJ Report in this Cause contains a highly-detailed examination of the extant issues with supporting analysis of each and extensive citation to the record evidence. While OG&E does not wholly agree with the ALJ’s determination regarding a few of the issues, the vast majority of his determinations are supported by the record evidence and detailed, transparent analyses. In a very few instances, OG&E submits that the ALJ may have misunderstood OG&E’s position or made a recommendation contrary to the record evidence, which OG&E will identify and discuss below. However, OG&E believes that, on the whole, the ALJ Report constitutes a detailed examination of the issues that, if adopted by this Commission, would easily withstand the rigors of appellate review.

With the changes requested in these exceptions, the implementation of the ALJ Report would result in an overall OG&E revenue requirement increase of approximately \$56.4 million. While this is approximately \$16 million above the \$40.7 million recommended revenue requirement increase contained in the ALJ Report, it is \$36.1 million lower than OG&E’s original request of about \$92.5 million. Given that OG&E implemented an interim rate increase

of approximately \$69 million in July 2016, an order adopting the ALJ Report with the changes requested herein would result in OG&E providing refunds to customers.

As this Commission is aware, its findings of fact and conclusions of law must be upheld if they are supported by substantial evidence. *Public Service Co. of Oklahoma v. Oklahoma Corporation Commission*, 688 P.2d 1274 (1983). Substantial evidence means something more than a scintilla of evidence and evidence that possesses something of substance and of relevant consequence and is such evidence that reasonable men may fairly differ to whether it establishes a case. *State ex rel. Cartwright v. Oklahoma Natural Gas Co.*, 640P.2d 1341 (1982); see also *Pannell v. Farmers Union Cooperative Gin Assn.*, 138 P.2d 817 (1943); *Pierce v. Underwood*, 487 U.S. 552, 564-65 (1988); *Application of Valliant Tel. Co.*, 656 P.2d 273, 275 (1982). The ALJ Report contains substantial evidence to support its recommendations and an order adopting such recommendations.

II. EXCEPTIONS

a. Return on Equity ("ROE")

The ALJ Report's recommendation in favor of a 9.87% return on equity ("ROE") for OG&E is well supported by the record. (ALJ Report, pp. 21-31). After detailed consideration of the witnesses' ROE proposals, the ALJ found that based on "all of the ROE evidence, . . . appropriate benchmarks point to 9.87 percent for the allowed ROE, with a 'range of reasonableness' between 9.7 and 10.0 percent." (*Id.* at 30). The lower boundary of the ALJ's "range of reasonableness" was informed by a "regional benchmark." (*Id.*). Specifically, the ALJ cited a 2015 rate order in which the Texas Public Utilities Commission awarded a 9.7% ROE to Southwestern Public Service Company ("SPS"). (*Id.* (citing Trial Ex. 61)). To establish the upper boundary, the ALJ relied upon a combination of the upper end of OIEC/OER witness Parcell's comparable earnings model (10.0%) and the upper end of OG&E witness Hevert's multistage DCF model (9.96%). (*Id.*). Then, the ALJ concluded that OG&E would need an allowed ROE of 9.868%, based on the Company's current capital structure and cost of debt. (*Id.*) The ALJ rejected the lower ROEs proposed by the intervenors, finding that their recommendations ranging from 8.9% to 9.3% would constitute an "extreme" drop in the current economy. (*Id.*)

While the Company requested a 10.25% ROE and believes that the record supports a ROE higher than the ALJ's recommendation, the ALJ Report is well-reasoned and identifies a reasonable recommendation. Nevertheless, the Report did not marshal all of the persuasive evidence of record in support of the recommended ROE range and ROE. As shown below, there is substantial additional evidence - stemming from the testimony of both OG&E's and the intervenors' witnesses - that directly supports the ALJ's recommended range of reasonableness as well as his specific ROE recommendation.

As an initial matter, the ALJ properly considered SPS's recently awarded ROE in reaching his conclusions. The returns authorized for vertically integrated electric utilities are highly observable and relevant benchmarks for assessing the reasonableness of OG&E's return. (Hevert Rebuttal, pp. 11-12). And, as OIEC/OER witness Parcell admitted at hearing, looking to

the ROE awards of other commissions can provide "assistance" and "comfort" when determining the reasonableness of an ROE recommendation. (Tr. A.M. 5/9/2016, p. 63, lns. 3-7). However, as shown below, the ALJ did not include in his Report additional record evidence that further supports his ROE recommendation.

For example, Mr. Hevert demonstrated that in 38 cases decided from 2014 through 2015, the average authorized return for vertically integrated electric utilities was 9.84%, and in 12 (i.e., about a third) of those cases, the authorized ROE was 10.0% or higher. (Hevert Rebuttal, p. 12, lns. 1-4). Thus, the ALJ's specific recommendation of 9.87% is eminently reasonable and the ALJ's upper boundary of 10.0% is conservative. While the Report references Mr. Hevert's testimony on this point, the ALJ did not explain that this testimony directly supports his specific recommendations. (ALJ Report, pp. 26-27(discussing Hevert's testimony); ALJ Report, pp. 30-31 (explaining the ALJ's ROE recommendation)).

Similarly, as OG&E witness Rowlett illustrated, the average authorized ROE since 2012 is 10.2% for utilities with debt credit ratings similar to or higher than OG&E's credit rating. (Rowlett Direct, p. 20, lns. 15-21 and Ex. DRR-2). Further, as Mr. Rowlett's Exhibit DRR-1 shows, the average ROE awarded over the past several years in "above average" rated regulatory jurisdictions is 10.26% and the average ROE awarded in "average" rated regulatory jurisdictions is 9.9% for vertically integrated companies. The ALJ did not reference Mr. Rowlett's testimony, despite the obvious evidentiary support it lends to his conclusions.

Admissions elicited at hearing, but unmentioned in the Report, also support the ALJ's recommendation. Indeed, several intervenor witnesses admitted that authorized returns for vertically integrated companies averaged over 9.70% in 2015. (Tr. A.M. 5/9/2016, p. 68, ln. 13 through p. 69, ln. 7 (Mr. Parcell admitting that authorized ROEs for vertically integrated utilities averaged 9.74% in 2015 and that in five cases, commissions authorized ROEs above 10.0%); Tr. A.M. 5/10/2016, p. sd-59, ln. 21 through p. sd-60, ln. 3 (Mr. Solomon admitting that ROEs authorized in 2015 for vertically integrated utilities averaged over 9.70%); Tr. P.M. 5/10/2016, p. rdh-16 through rdh-17 (Mr. Walters admitting that authorized ROEs for vertically integrated utilities averaged 9.74% in 2015 and that in five cases, commissions authorized ROEs above 10.0%)). Thus, even those witnesses who otherwise recommended lower ROEs cannot claim that the ALJ's recommendation is out of step with recent, relevant decisions. The ALJ could have made that point clear.

In the same vein, the ALJ could have recognized the evidence distinguishing between vertically integrated utilities and distribution-only companies. The ALJ noted that "both sides of the ROE dispute can point to allowed ROEs elsewhere that are above or below 9.87% for an allowed ROE." (ALJ Report, p. 30). That may be true, but the relevant consideration here is the returns authorized for vertically integrated utilities like OG&E. As Mr. Hevert explained, vertically integrated utilities own generating assets that present a host of risks to which distribution-only companies are not exposed. (Hevert Rebuttal, p. 78, lns. 3-7; Tr. A.M. 5/5/2016, p. SJ-138, ln. 16 through p. SJ-139, ln. 10). Even AG witness Solomon admitted that distribution-only companies do not have any of the risks of operating generation plants, including risks with respect to fuel procurement, environmental compliance for generation, and the risks associated with cost recovery related to environmental capital expenditures. (Tr. A.M.

5/10/2016, p. sd-58, ln. 10 through p. sd-59, ln. 4). That is why comparisons between OG&E and distribution-only utilities - that have fundamentally different risk profiles and that, all else equal, require a lower ROE - should be afforded little weight. And, as illustrated above, the evidence demonstrates that the ALJ's recommendations are fully supported by recent authorized returns for vertically integrated companies.

Regarding the intervenors' witnesses' proposals, Mr. Hevert also demonstrated that making certain reasonable adjustments to their calculations produced results in ROE estimates that range from 9.78% to 9.83%.¹ (Hevert Rebuttal, p. 146, ln. 9 through p. 147, ln. 2 and Table 12). While the Report acknowledges Mr. Hevert's analysis (even reproducing Table 12 from his Rebuttal Testimony), the ALJ did not make clear that Mr. Hevert's reasonable adjustments would: (1) bring the other witnesses' proposals within the range of recently authorized ROEs for vertically integrated companies; and (2) bring the other witnesses' proposals squarely within the range of the ALJ's "range of reasonableness" and very near to his 9.87% recommendation.

¹ The specific adjustments made by Mr. Hevert are explained throughout his Rebuttal Testimony and are supported by other testimony. First, Mr. Hevert adjusted Mr. Garrett's DCF analysis to include only Value Line EPS growth rate projections (eliminating the effect of Mr. Garrett's historical growth rates which are inappropriate for a forward looking analysis like DCF, Hevert Rebuttal, p. 22, lns. 9-12), which resulted in an average ROE of 9.60%. (Hevert Rebuttal, p. 31, lns. 1-3, Ex. RBH-30R, and Table 12). Mr. Hevert also revised Mr. Garrett's CAPM analysis to include more reasonable Value Line beta coefficients (rather than Mr. Garrett's calculated beta coefficients) and a 9.53% market risk premium (rather than Mr. Garrett's 5.85% figure which is about half of the historical average for risk premia since 1926, *id.*, p. 53, Chart 7), resulting in a mean estimate of 10.05%. (*Id.* at p. 54, n. 1-3, Ex. RBH-31R, and Table 12). Averaged together, these analyses result in a 9.83% ROE estimate. (*Id.* at Table 12). Second, Mr. Hevert revised the Equity Risk Premium analysis presented by Mr. Walters by performing two regression analyses using data provided in exhibits to Mr. Walters' testimony. (*Id.* at p. 116, ln. 11 through p. 117, ln. 4 and Table 7). This corrected for Mr. Walters' Equity Risk Premium values, many of which were out of date and unrepresentative. (*Id.*, p. 113, ln. 3 through p. 115, ln. 9.) As revised by Mr. Hevert, that analysis resulted in an ROE estimate of 10.53%. (*Id.*). Averaging this result with two of Mr. Walters' DCF and CAPM analyses, Mr. Hevert calculated an average ROE estimate of 9.80%. (*Id.*, Table 12). Third, Mr. Hevert revised Mr. Parcell's CAPM analysis to apply Mr. Hevert's market risk premium estimate. (*Id.* at p. 137, lns. 5-9). Mr. Parcell's market risk premium analysis was at odds with the historical data he purported to rely upon and was inconsistent with the demonstrated relationship between those premia and interest rates. (*Id.*, p. 136, ln. 4 through p. 137, ln. 4.) So modified, Mr. Parcell's CAPM analysis estimates a 10.60% ROE, which, when averaged with Mr. Hevert's 10.30% CAPM estimate, results in an average ROE estimate of 10.45%. (*Id.*). When that result is averaged with Mr. Parcell's DCF estimate using First Call EPS growth rates, the average ROE estimate is 9.78%. (*Id.* at Table 12). Taken together, Mr. Hevert's adjustments result in ROE estimates ranging from 9.78% to 9.83%.

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%

In short, the ALJ's conclusions are proper, but the record provides far more support for those conclusions than was articulated in the Report. The ALJ correctly recognized that "the cost of equity is not directly observable but must be estimated from quantitative and qualitative information" and that since "no individual model is more reliable than all others under all market conditions," analysts "should gather and evaluate as much relevant data as reasonably can be analyzed." (ALJ Report, p. 24.) He simply did not go far enough in identifying and explaining the relevant data supporting the Report's ROE conclusions. The ALJ could have made explicit that much of the other evidence further buttresses his conclusions.

The ALJ also erred by criticizing Mr. Hevert's growth rate of 5.22%. (ALJ Report, pp. 27-28). In fact, Mr. Hevert's growth rates are reasonable, especially when compared to the analyses of other witnesses. For example, Mr. Parcell admitted that all five of his calculated DCF values that fell within his ultimate recommended range were derived using growth figures greater than 5%. (Tr. A.M. 5/9/2016, p. 78, ln. 21 through p. 79, ln. 6). Mr. Walters acknowledged that within his recommended DCF range for Constant Growth Rate DCF, there were more values that used consensus analysts' growth rates which had an average higher than Mr. Hevert's value than using other growth rates. (Tr. P.M. 5/10/2016, p. rdh-23 through p. rdh-26). And of the three growth calculations that Mr. Walters used, only the calculations using consensus analysts' growth rates of 5.53% produced mean or median values for his proxy group that were within his recommended range of ROEs. (*Id.*). Thus, Mr. Hevert's growth rates were well supported by the testimony of other witnesses. Given that the ALJ's criticism of Mr. Hevert's growth rate was in error, an ROE value that was higher than the ALJ's recommended value could be supported.

While the Company believes that the record could support a ROE higher than the ALJ's recommendation, the recommended 9.87% ROE is fully supported by recent authorized returns for vertically integrated utilities, by the authorized returns for utilities with credit ratings similar to OG&E's, by the returns authorized for utilities operating in similar regulatory jurisdictions,

and even by many of the intervenors' witnesses' calculations, as modified by Mr. Hevert's reasonable adjustments.

b. Production Tax Credits ("PTCs")

The uncontroverted facts presented in this cause are that known and measurable changes caused by PTC credits expiring subsequent to the end of the test year will substantially reduce the revenue that the Company would otherwise lawfully be entitled to receive from the rates approved by this Commission. Those reductions are estimated to be approximately \$9 million in 2017 and \$11.5 million in 2018. Further, the Company would note that additional reductions in 2019 and 2020 will occur in the amounts of \$8.9 million and \$22.9 million, respectively. (Rowlett Rebuttal, p. 13, Ins. 23-24). The record also demonstrates that the Company's proposal to rely on the Fuel Adjustment Clause to remedy this inequity is both lawful and appropriate; and that the implementation of a stand-alone rider or regulatory asset, while not as efficient as the FAC approach, would also reasonably dispose of the issue.

As the Commission is aware, a PTC is a tax credit which reduces the income taxes of qualified tax-paying owners of renewable energy projects based on the electrical output (measured in kilowatt-hours, or kWh) of grid-connected renewable energy facilities. (Rowlett Direct, p. 13, Ins. 26-27). PTCs, which are available for the first ten years of production from an eligible turbine, have been used to reduce the income tax expense component of the Company's cost of service and to reduce the cost recovered through individual project riders. (*Id.* at 14, Ins. 4-6).

As these PTCs expire between rate cases, OG&E sought a way to adjust rates to fairly reflect the actual benefit passing to customers. For example, in December 2016, the PTCs associated with 19 turbines at the Centennial Wind Facility have now expired and; in March 2017, the remaining credits from Centennial will expire. (Rowlett Rebuttal, p. 13, Ins. 10-26). Without a mechanism to adjust PTCs in 2017, OG&E would pass an extra credit to customers of \$9,098,913; a value of PTCs that OG&E no longer received. Without the requested relief in this cause, OG&E would lose that \$9,098,913 and that amount would never be recoverable simply because of the timing of rate cases and the inability to process another rate case within 2017. (*Id.*) This trend will continue into 2018 with another \$11,591,262 of PTC credits passing to customers even though those PTCs will have expired. (*Id.*) This loss of over \$20 million is significant, especially when considering that options for an efficient means of passing these credits through to customers exists.

In order to address this problem, OG&E requested that the Fuel Adjustment Clause ("FAC") be used to credit customers for the value of PTCs from the Centennial, OU Spirit and Crossroads wind farms. This would allow customers to receive the credits associated with PTCs and allow the Company to adjust the PTC credits as they expire. In response to OG&E's request, the ALJ stated: "With respect to the PTCs, the ALJ submits that OG&E needs to apply for either a rider or a regulatory asset." (ALJ Report, p. 67).

OG&E continues to believe that including PTCs in the FAC makes sense from a practical perspective and a regulatory efficiency perspective. The amount of PTCs generated is highly

variable and directly tied to the volume of energy produced from the wind farms. (Rowlett Rebuttal, p. 14, lns. 14-20). Wind power is commonly referred to as “variable renewable energy” in that it is non-dispatchable due to its fluctuating nature. (*Id.*) Wind generation output varies by hour, day, month, and season. (*Id.*) Because PTCs are directly related to production and that production is variable, it is appropriate to include PTC credits in the FAC. (*Id.*) This suggests that the FAC is the appropriate mechanism for passing through PTC credits. (Rowlett Direct, p. 14, ln. 14-15). Moreover, since they correlate with the production from OG&E's wind farms, including them in the FAC would allow for an annual auditing of the PTCs through the annual fuel prudence review. Thus, the Commission already has an existing annual mechanism to timely review PTC credits and will not have to create new review processes. When such an annual process exists related to the FAC, it would be highly inefficient and wasteful to require that the Company file rate cases every time a tranche of PTCs expire.

OG&E notes that, Witness Rowlett, in his rebuttal testimony, stated OG&E's preference to move PTCs into the FAC, but stated no objection to “moving the PTCs into a mechanism other than the FAC.” (Rowlett Rebuttal, p. 13.) Additionally, in OG&E's Proposed Order, it provided a proposed finding for “inclusion of PTCs in the FAC (or a stand-alone rider)...” (OG&E's Proposed Order, p. 53). While the FAC seemed to be the best mechanism for including PTCs, OG&E indeed proposed, in the alternative, a stand-alone rider in this proceeding. OG&E has several riders that provide credits to customers that could be used as a template for a stand-alone PTC rider. Such riders include the Rider for Cogen Credit (which credits to customers cost reductions associated with cogeneration), the Renewable Transmission Systems Additions rider (which credits renewable energy credit revenues to customers), and the Crossroads rider (which currently credits to customers PTCs associated with the Crossroads Wind Facility).

It also should be noted that PUD staff did recognize the problem of expiring PTCs remaining in base rates and the need for some kind of action. Staff witness Thompson stated that “[t]he PTCs for wind projects have a 10 year term and will be expiring in two or three years. To provide that the proper PTCs are provided to consumers a change of this type is necessary.” (Thompson Responsive, p. 26). PUD staff acknowledged a financial impact to the Company resulting from the expiration of PTCs if they remained in rate base and stated: “Without an order of the Commission allowing the PTCs to be moved to a rider or a regulatory asset the Company will need to file another rate adjustment proceeding to properly reflect the expiration of these PTCs.” (Thompson Responsive, p. 27). No other witness addressed the issue of moving PTCs into a stand-alone rider (other than the FAC) or establishing a regulatory asset.

Based upon the importance of addressing this issue in this present rate case, OG&E requests that this Commission, if it decides to adopt the ALJ Report, amend the ALJ's recommendation on PTCs and approve a stand-alone rider for the purpose of crediting wind energy PTCs to customers. Such an amendment is consistent with the ALJ's recommendation, recognizes the alternative proposal endorsed by the Company and addresses the problem recognized by PUD Staff. Alternatively, the Commission could allow OG&E to establish a regulatory asset beginning when the PTCs expire for ultimate true up and recovery in the next rate case. Even if the Commission does not approve the inclusion of PTCs in the FAC, it has the ability to approve the inclusion of PTCs in a stand-alone rider or approve a regulatory asset in

this current proceeding. It would be inefficient for the Commission to require OG&E to open an entirely new Cause in order to request the same relief that the Commission can approve in the current proceeding.

c. Air Quality Control Systems ("AQCS")

The Company believes that some kind of periodic adjustment mechanism is appropriate for recovering AQCS costs because of the unpredictability associated with the dispatch of generation in the SPP Integrated Marketplace ("IM"). (Rowlett Direct, p. 16, lns. 13-15). If the costs are in base rates, in any given year, the Company stated that customers will under or over pay for this cost. (*Id.* at lns. 15-16). OG&E believes that inclusion of AQCS costs in the FAC not only eliminates such an under and over recovery problem, but it simply makes sense from a regulatory efficiency standpoint – the mechanism and the annual review process already exist. In the alternative, the establishment of a regulatory asset/liability is another way to ensure that these highly variable and unpredictable AQCS costs are tracked between rate cases to ensure customers do not over or under pay for this cost.

In his Report, the ALJ correctly observed that OG&E had previously raised the issue of moving AQCS costs from base rates to the FAC in Cause No. PUD 201400229 and that such request had been denied. (ALJ Report, p. 67). Regarding the present request, the ALJ stated that he "rejects OG&E's current reiteration of its AQCS argument based on that prior ruling but suggests that OG&E apply for a rider." (*Id.*)

In Order No. 647346, issued in PUD No. 201400229, the Commission addressed OG&E's request to recover power plant consumables through the FAC. *See* Order No. 647346, p. 17. In response to that request, the Commission stated:

OG&E claimed these costs vary with production of electricity, however, that is not a sufficient basis for recovering these costs through the FAC. Other costs for the utility may also fluctuate in such a manner, but that *alone* would not be a compelling reason to include them in the FAC. *Moreover, 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.*
Id. (Emphasis added).

OG&E reasserts its argument that the costs of AQCS consumables are appropriately recovered through a mechanism like the FAC in that those costs vary directly with the quantity of electricity produced. As stated by OG&E witness Rowlett: "As more electricity is generated, more emissions are created and more consumables are needed to control the emissions impact. Therefore, consumable costs vary with the amount of energy produced from the generating units and these costs are directly correlated to the amount of fuel consumed." (Rowlett Direct, p. 16).

However, in the present Cause, Mr. Rowlett's justification for recovering consumables through the FAC was based on more than a correlation between energy production and cost. Mr. Rowlett also based his argument on the unpredictable nature of the costs and the fact that if the costs remain in base rates, customers will over- or under-pay during any given time period.

(Rowlett Direct, p. 16). Mr. Rowlett further noted that the market price the Southwest Power Pool pays OG&E for the power sold into the SPP IM includes the cost of AQCS and that the Company currently includes the cost of generation fuel in the FAC and credits the FAC for revenue received from the SPP IM. (Rowlett Direct, p. 17). Since IM Sales revenue is a credit through the FAC, including AQCS expenses in the FAC would properly match the actual revenues received with actual expenses incurred. Also, by including AQCS costs in the FAC, a review of the SPP IM revenues during the annual fuel prudence reviews will be easier and more transparent because market revenues net of fuel and AQCS costs more completely reflect the value of SPP transactions to OG&E customers. OG&E submits that the ALJ failed to recognize and address the additional bases presented by OG&E during this Cause to justify recovery of AQCS costs through the FAC.

Moreover, the Commission has now approved FAC recovery of AQCS consumables for two other Oklahoma electric utilities, Empire District Electric Company and Public Service Company of Oklahoma.² Also, the ALJ failed to recognize that AQCS (and PTCs as discussed above) are generation related costs that should be included in the FAC like other costs have in the past. For example, the Commission has allowed the proceeds from the sale of SO₂ allowances to be passed through the FAC.³ OG&E has also been permitted to include proceeds from sales of ash and other coal combustion byproducts in the FAC.⁴ In addition, the Commission has also allowed OG&E to include costs associated with wildlife mitigation through the FAC.⁵ OG&E requests that the Commission alter the ALJ's recommendation with regard to AQCS costs and approve the inclusion of such costs through the FAC.

OG&E would also show that in testimony supporting the Application in the present Cause, an alternative recommendation was included should the Commission again deny recovery of AQCS through the FAC. That alternative was to establish a regulatory asset/liability to track actual AQCS costs that are below or above the amount in base rates. (Rowlett Direct, p. 18). OG&E submits that the ALJ did not consider OG&E's alternative request of a regulatory asset/liability and did not address the issue in his ALJ Report. Additionally, OG&E would show that no witness addressed, or objected to, the establishment of a regulatory asset/liability for these AQCS costs.

If the Commission does not approve FAC recovery of these AQCS costs, OG&E requests that the Commission approve the establishment of a regulatory asset/liability for AQCS costs consistent with OG&E's original request. Lastly, OG&E submits that it is within the discretion of this Commission to allow OG&E to initiate a rider to recovery AQCS costs as recommended by the ALJ in his Report. Even if the Commission does not allow AQCS costs to be included in the FAC, it has the ability to approve the inclusion of AQCS costs in a stand-alone rider or approve a regulatory asset in this current proceeding. It would be inefficient for the Commission

² Empire District Electric Company, Cause No. PUD 201100082, Order No. 592623; Public Service Company of Oklahoma, Cause No. 201500208, Order No. 657877.

³ See Order No. 526426, Cause No. 200600041, at 6.

⁴ See Order No. 128260, Cause No. 25943 at 4.

⁵ See Order No. 572636, Cause No. 200900230, at 8.

to require OG&E to open an entirely new Cause in order to request the same relief that the Commission can approve in the current proceeding.

d. Depreciation

Depreciation expense, when properly calculated and recovered, allows all customers who benefit from a utility's use of an asset to pay for that asset in an orderly and equitable manner. (Spanos Rebuttal, p. 6, Ins. 11-24). Two key aspects of determining the proper depreciation of an asset are the asset's expected service life and the value of that asset when it retires from service. As to the latter, part of that value includes the cost of taking the asset out of service. That cost should be subtracted from the salvage value of the asset. (*Id.* at p. 14, Ins. 8-24 (explaining the concept of "terminal" net salvage)).

The issue of depreciation is an important one because any unreasonable depreciation rates set by this Commission may lead to OG&E's independent auditors and other regulatory bodies requiring a separate set(s) of books. It would be highly problematic for this Commission's depreciation rates to be used for rate recovery purposes while OG&E's independent auditor requires separate rates for its financial statements prepared in accordance with Generally Accepted Accounting Principles and perhaps the Arkansas and FERC jurisdiction requiring more reasonable depreciation schedules for those jurisdictions.

Here, the ALJ admirably weighed into the technical details of the depreciation evidence. Nevertheless, the ALJ should have accepted OG&E's witness' conclusions with regard to (1) the service lives of OG&E's assets for certain mass property accounts; and (2) the terminal net salvage values for production plant.

In this proceeding, only one witness - OG&E witness John Spanos - presented the results of a full scale study of the service lives OG&E's assets. After concluding that Mr. Spanos' experience and study made his conclusions more reliable for the service lives of certain assets, the ALJ proceeded to downplay Mr. Spanos' conclusions regarding the service lives of other assets. (*Compare* ALJ Report, p. 57 *with* ALJ Report, p. 63). This unexplained inconsistency has no basis in the record. Mr. Spanos' conclusions regarding service life spans should be accepted for all of OG&E's assets studied by him. As detailed below, Mr. Spanos, alone among all of the witnesses who testified on depreciation issues, had an intimate understanding of OG&E's assets. He was the only witness who had performed multiple depreciation studies on behalf of OG&E, conducted interviews with OG&E operating personnel and management, and inspected Company plant over the years.

Similarly, the ALJ recommended an inadequate level of recovery for annual net terminal salvage for the Company's production plant. Mr. Spanos' conclusions regarding the cost of decommissioning those assets are the only values supported in the record. As the ALJ recognized, not allowing any terminal net salvage cost would result in an intergenerational subsidy; customers taking service at the end of the plant's life would pay a cost for an asset used by customers taking service over the assets life (which typically spans decades). While the ALJ correctly concluded that OG&E should be allowed to begin separately collecting an amount for production plant terminal net salvage, the Commission must begin allowing the Company to

recover the full amount of its estimated costs now to prevent the cost burden from being unduly shifted to future ratepayers.

1. Mass Property Service Life Spans

In his consideration of the depreciation witnesses' proposals concerning mass property service life spans, the ALJ identified the heart of the dispute: the application of informed judgment. (ALJ Report, p. 62). Indeed, as the ALJ explained, "because each expert used the same statistical analyses, the differences between [their] estimates results from the application of informed judgment." (*Id.* (citing Spanos Rebuttal, p. 27, lns. 10-12)). The ALJ also acknowledged that OG&E witness Spanos applied his judgment on the basis of "four depreciation studies [for OG&E] over a fifteen-year period" and his "industry experience." (*Id.* at pp. 57, 63). Despite Mr. Spanos' extensive experience, however, the ALJ recommended "splitting the difference," resulting in a recommended \$3.35 million reduction to depreciation expense. (*Id.* at pp. 63-64). According to the ALJ, he arrived at this recommendation because, although he found the intervenors' testimony unpersuasive, "the problem is how you know that [Mr. Spanos'] opinion is correct" when "[he] failed to present anything other than his assertions that his survivor curve analysis is correct." (*Id.* at 63). Respectfully, the ALJ's recommendation should be amended and the Commission should adopt Mr. Spanos' mass property service life recommendations in their entirety, resulting in a \$3.35 million increase in the ALJ's depreciation expense recommendation.

The application of informed judgment is a critical and inherently subjective part of any depreciation study. (Tr. A.M. 5/16/2016, p. sd-78, ln. 18 through p. sd-79, ln. 8 (Pous Cross); ALJ Report, p. 63). A leading authority on depreciation analysis, the Public Utility Depreciation Practices Manual published by the National Association of Regulatory Utility Commissioners ("NARUC"), explains the importance of this process. (Spanos Rebuttal, p. 7, ln. 16 through p. 8, ln. 1); Trial Ex. 57). According to the NARUC Manual, informed judgment is based on a combination of general experience, knowledge of the properties under study, physical inspection, information gathering on the industry, past company studies, and other factors. (Trial Ex. 57, p. 128; ALJ Report, p. 63). The Manual expressly recognizes that "the use of informed judgment sometimes becomes a point of controversy in the regulatory setting because *some of the analyst's opinions cannot be quantified or easily supported,*" making it "*sometimes impossible to pinpoint the reasons for making a decision* that diverges from a company's historical data or standard reference material." (Trial Ex. 57, p. 129; Tr. A.M. 5/16/2016, p. sd-80, lns. 14-25 (Pous Cross) (emphasis added)). Emphasizing the necessity of judgment to a depreciation study, the NARUC Manual further states, "The use of judgment can be a major factor in forecasting[,]" and "[i]t is the analyst's *responsibility* to apply any additional known factors" to determine the best estimates. (Trial Ex. 57, pp. 128-29 (emphasis added)).

There can be no reasonable dispute that OG&E witness Spanos was best positioned to exercise informed judgment to estimate the service lives of the assets in the mass property accounts. Over the course of 30 years, Mr. Spanos has conducted more than 500 depreciation studies and testified in more than 200 cases before 40 regulatory commissions. (Tr. A.M. 5/12/2016, p. 8, lns. 13-18 (Spanos Direct); Spanos Direct, p. 2, lns. 19-23). The methods and procedures he utilized in this case are the same or substantially similar to those he has employed

in the hundreds of other studies he has performed. (Tr. A.M. 5/12/2016, p. 8, ln. 23 through p. 9, ln. 11 (Spanos Direct)). In no case has a commission rejected Mr. Spanos' methodology and procedures. (*Id.* at p. 9, lns. 12-17). Here, Mr. Spanos alone had extensive experience with and relied upon detailed information about OG&E's assets. During the last 15 years, Mr. Spanos has conducted four depreciation studies on behalf of OG&E, and in each of these, he has used a substantially similar methodology. (*Id.* at p. 8, ln. 19 through p. 9, ln. 11). He interviewed operating personnel, participated in discussions with management, and conducted site visits to inspect the Company's plant. (*Id.* at p. 8, ln. 23 through p. 9, ln. 11; Spanos Direct, p. 5, lns. 1-8). He thus developed an intimate understanding of OG&E's assets.

In contrast, no other witness physically inspected the assets subject to the depreciation study, discussed the assets with OG&E's field personnel, or interviewed OG&E's management regarding the Company's plans and policies related to the assets. (Tr. A.M. 5/16/2016, p. sd-78, lns. 10-17 (Pous Cross); Tr. Late P.M. 5/18/2016, p. sd-21, lns. 4-21 (Andrews Cross); Tr. Late P.M. 5/18/2016, p. sd-51, ln. 20 through p. sd-52, ln. 4 (Garrett Cross)). Further, Mr. Andrews' and Mr. Garrett's experience pales in comparison to Mr. Spanos' experience. Prior to this case, Mr. Andrews had testified in only two cases, both in 2016. (Tr. Late P.M. 5/18/2016, p. sd-14, lns. 15-18 (Andrews Cross)). Similarly, Mr. Garrett had testified on depreciation issues only three times and had not testified on depreciation issues prior to 2015. (Tr. Late P.M. 5/18/2016 Tr., p. sd-49, lns. 14-19 (Garrett Cross)). Mr. Garrett and Mr. Andrews also received their training in depreciation from individuals who work for Mr. Spanos. (Tr. Late P.M. 5/18/2016, p. sd-15, lns. 12-26 (Andrews Cross); *id.* at p. sd-49, ln. 20 through p. sd-50, ln. 9 (Garrett Cross)).

Although the ALJ recognized that the application of informed judgment is "the subjective part" of the depreciation study, he discounted Mr. Spanos' experience and diligence in support of his application of judgment while disregarding the intervenors' lack thereof. (ALJ Report, p. 63). In fact, the ALJ's stated basis for not accepting Mr. Spanos' opinions fully – that Mr. Spanos "failed to present anything other than his assertions" – is not only untrue, it also ignores the teachings of the NARUC Manual. Since he started conducting depreciation studies on OG&E's behalf, Mr. Spanos has participated in more than 30 site visits to inspect the Company's plant, analyzed the Company's current policies and outlook, interviewed operating personnel, and participated in discussions with management. (Spanos Direct, p. 5, lns. 1-8; Spanos Direct, Ex. JJS-2 at pp. III-2 to III-3; Tr. A.M. 5/12/2016, p. 8, ln. 23 through p. 9, ln. 11 (Spanos Direct)). That "some of [Mr. Spanos'] opinions cannot be quantified or easily supported," Trial Ex. 57, p. 129, is not a reason to reject Mr. Spanos' estimates.

The ALJ's reluctance to adopt Mr. Spanos' opinions regarding the mass property accounts is especially puzzling given that the ALJ expressly acknowledged Mr. Spanos' superior experience and judgment earlier in his report. When considering the witnesses' positions on steam production plant life spans, the ALJ stated:

[T]he 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. (ALJ Report, p. 57).

The ALJ's sudden change of course just six pages later in the Report is never explained. The differences between Mr. Spanos' estimates and those of Staff witness Garrett, FEA witness Andrews, and OIEC/OER witness Pous come down to the application of each witness' experience to his specific knowledge of OG&E's specific assets. And the record shows that Mr. Spanos is the only witness with the experience and the knowledge of OG&E's assets to be in a position to exercise *informed* judgment.

Apart from the vast differences in experience and reliance on detailed OG&E information between Mr. Spanos and the witnesses who opposed him, the record also demonstrates why Mr. Garrett's, Mr. Andrews', and Mr. Pous' estimates are not as reasonable as those provided by Mr. Spanos. Both Mr. Garrett and Mr. Andrews asserted that their proposed mass property survivor curves should be adopted because they provide better mathematical fits to the historical data. (Garrett Responsive, p. 21, lns. 12-18⁶; Andrews Responsive, p. 14, lns. 5-7). As the ALJ observed, however, "a survivor curve should not be taken at face value without considering what is happening in the account." (ALJ Report, p. 63). Mr. Garrett and Mr. Andrews admitted as much at hearing. (Tr. Late P.M. 5/18/2016, p. sd-18, ln. 17 through p. sd-19, ln. 3 (Andrews Cross); Tr. Late P.M. 5/18/2016, p. sd-50, ln. 14 through p. sd-51, ln. 19 (Garrett Cross)). But, as discussed, neither Mr. Andrews nor Mr. Garrett interviewed OG&E operating or management personnel regarding the plant's operating environment and/or the Company's policies, and neither witness inspected the Company's plant. That is why the ALJ should not have simply split the difference between their estimates and those proposed by Mr. Spanos; there is simply no foundation for these witnesses' application of judgment, to the extent they exercised any at all.

Mr. Spanos demonstrated the dangers of making service life estimates based on rigid adherence to mathematical curve fitting - and the failure to apply informed judgment - by pointing to one of Mr. Garrett's analyses. For Account 368 (Line Transformers), Mr. Garrett recommended a 44-O2 curve, which, as Mr. Spanos explained, leads to unreasonable results. (Spanos Rebuttal, p. 30, ln. 26 through p. 32, ln. 7 and Figure 2). Mr. Garrett's recommended curve predicts that about a quarter of the assets in the account will be in service at least 60 years, and that a large percentage of the assets that reach age 60 will remain in service for over 100 years. (*Id.*). Taken together, these two estimates reveal that Mr. Garrett inexplicably assumes that the retirement rate for the assets will slow dramatically as the assets age beyond 60 years: *e.g.*, a large percentage of the assets that reach age 60 will survive to age 100. (Tr. Late P.M. 5/18/2016, p. sd-64, ln. 23 through p. sd-65, ln. 2 (Garrett Cross)).

At hearing, Mr. Garrett could not provide any explanation for this unreasonable assumption. (*Id.* at p. sd-66, lns. 12-15). Mr. Spanos testified that the "survivor curve" (a key

⁶ Although Mr. Garrett claimed at hearing that he used "judgment" and not simply mathematical curve fitting to develop his survivor curve recommendations, (Tr. Late P.M. 5/18/2016, p. sd-47, ln. 20 through p. sd-48, ln. 17), he admitted that he primarily relied on mathematical curve-fitting. (*Id.* at p. sd-60, lns. 9-21).

determinant in forecasting average service life) chosen by Mr. Garrett for his service life calculations for this account is not used for utility assets because it predicts, as Mr. Garrett's analysis bears out, that a portion of the assets will survive much longer than the remainder of the account. That is, using Mr. Garrett's curve will unreasonably skew the average service life of the assets in this account towards the estimated end of the life of the longest lasting asset in this account. (Spanos Rebuttal, p. 32, lns. 1-7). Mr. Garrett could not refute that fact. (Tr. Late P.M. 5/18/ 2016, p. sd-66, ln. 23 through p. sd-67, ln. 3 (Garrett Cross)). And Mr. Garrett later testified that his analysis for Account 368 was "just the same" as for the other accounts for which he recommends adjustments. (*Id.* at p. sd-73, lns. 20-24). These manifestly unreasonable results highlight the dangers of overreliance on statistical curve fitting and show why the ALJ was not justified in just splitting the difference between the witnesses' estimates.

OIEC/OER witness Pous' estimates fare no better. Mr. Pous recommended adjustments to Account 350.2 (Transmission Land Rights), Account 353 (Station Equipment), Account 355 (Poles and Fixtures), and Account 356 (Overhead Conductors). Mr. Spanos' proposals for these accounts would result in either keeping or extending currently applicable service life estimates. The ALJ did not discuss any of the disputes regarding these specific mass property accounts. Mr. Pous failed to present any valid reason why the Commission should reject Mr. Spanos' reasonable and well-informed recommendations in favor of Mr. Pous' longer life estimates.

For Account 350.2 (Transmission Land Rights), Mr. Pous recommended using a 100-R4 life-curve combination (estimating a 100-year average life), as compared to the 75-R4 life-curve combination (estimating a 75-year average life) previously approved, currently in place, and recommended for continuation by Mr. Spanos. (Pous Responsive, p. 48, ln. 24). Mr. Pous therefore recommended increasing the average estimated service life for the assets in the account by 25 years. As Mr. Spanos explained, however, there is no reasonable basis for extending the current estimate by 25 years. Indeed, there has been little change to the assets in this account over time. (Spanos Rebuttal, p. 37, lns. 7-9). As Mr. Spanos showed, Mr. Pous' proposal would inappropriately increase the service life of these assets to be near the time at which the last of the assets will survive. (*Id.* at p. 37, lns. 9-13). Accordingly, there is no reason to deviate from current practice, and Mr. Pous' proposed 25-year increase in the average service life should have been rejected by the ALJ.

Regarding Account 353 (Station Equipment), Mr. Spanos proposed a 60 year service life, representing a 5-year increase in estimated service life as compared to the current 55-year estimate. (Spanos Rebuttal, p. 37, lns. 19-21). Mr. Pous would have the Commission adopt a 63-year service life. (Pous Responsive, p. 48, ln. 24). Again, however, Mr. Pous could not demonstrate that the assets in this account should have longer life estimates than those previously approved by the Commission and recommended by Mr. Spanos in this case. Indeed, Mr. Spanos' estimated service life is already longer than the industry standard and is placed at the upper end of the industry range. (Spanos Rebuttal, p. 37, ln. 23 through p. 38, ln. 3). Given that only 18 years of historical data is available for this account, it is not reasonable to extend Mr. Spanos' already conservative estimate another three years. (*Id.*)

For Accounts 355 (Poles and Fixtures) and 356 (Overhead Conductors and Devices, Mr. Pous proposed a 65-year average service life span for both accounts. (Pous Responsive, p. 48,

ln. 24). Mr. Spanos proposed to retain the current 55-year life span for Account 355 and 60-year life span for Account 356. (Spanos Rebuttal, p. 40, lns. 2-3; p. 41, lns. 25-26). For these accounts, the differences between Mr. Pous and Mr. Spanos can be attributed in large part to Mr. Pous' disregard for the retirement impact of ice storms in Oklahoma upon the assets in the accounts. (Spanos Rebuttal, p. 41, lns. 10-14; p. 41, lns. 24 through p. 42, ln. 4). The occurrence of ice storms in Oklahoma is neither anomalous nor unexpected. Indeed, Mr. Pous conceded that ice storms frequently occur in Oklahoma and in OG&E's service territory. (Tr. P.M. 5/16/2016, p. 1w-22, ln. 5 through p. 1w-24, ln. 9 (Pous Cross)). Mr. Spanos' analysis, which accounts for the likelihood of future ice storms, is therefore more reasonable. (Spanos Rebuttal, p. 41, lns. 10-22).

The ALJ should not have split the difference between Mr. Spanos' recommendations and those of the opposing witnesses regarding mass property service lives. While the application of informed judgment is inherently subjective, the ALJ should have recognized Mr. Spanos' substantial experience with OG&E's assets. The record is clear that: (1) Mr. Spanos is the only expert with any real and detailed knowledge of the Company's assets; (2) Mr. Garrett's and Mr. Andrews' overreliance on mechanical curve fitting leads to unreasonable results; and (3) Mr. Pous' failure to show that Mr. Spanos' estimates - which recommended keeping or even extending the previously approved and currently applicable estimates - are unreasonable. Mr. Spanos' recommendations should be adopted in their entirety.

2. Terminal Net Salvage

The ALJ recommended that the Commission allow OG&E to recover \$7.8 million annual net terminal salvage for the Company's production plant. (ALJ Report, p. 60). The ALJ arrived at this recommendation by, first, calculating the annual amount to be \$15.6 million⁷ (ALJ Report, p. 58) and, second, adopting Staff witness Garrett's recommendation that the Commission allow OG&E to recover half of the requested annual amount. (*Id.* at p. 60). The ALJ correctly concluded that OG&E should be allowed to begin separately collecting an amount for production plant net salvage. However, his recommendation will still shift a disproportionate amount of these costs to future generations of ratepayers. Thus, the Commission should instead adopt the Company's requested terminal net salvage cost estimates.

As an initial matter, the ALJ mischaracterized how OG&E witness Spanos arrived at his terminal net salvage estimated costs. According to the ALJ, "Mr. Spanos estimated net terminal salvage for steam plant . . . based on a published study from 1996" and for other production plant, excluding wind, and wind "based on a confidential study." (ALJ Report, p. 58). The ALJ's reference to Mr. Spanos basing his estimate for steam plant solely on "a published study from 1996" is contradicted by the record. As Mr. Spanos explained, the estimate that he used - \$40/kW hour - "is the most commonly utilized amount [for steam production plant] when considering all the industry estimates." (Tr. P.M. 5/12/2016, p. 1w-15, lns. 10-11 (Spanos Cross)). This amount was initially established in a study presented to the American Gas Association and the Edison Electric Institute, two respected utility associations. (*Id.* at p. 1w-15, ln. 12 through p. 1w-16, ln. 17 (Spanos Cross)). This study was the "initial step" in establishing

⁷ The total Company cost of terminal net salvage is \$18.3 million.

decommissioning costs, and the study's estimates have since been supplemented and supported by other studies conducted by other well-known and well-regarded entities, such as Sargent & Lundy and Burns & McDonnell. (*Id.* at p. 1w-18, ln. 10 through p. 1w-19, ln. 16 (Spanos Cross)).

Further, Mr. Spanos' estimates were also based on his experience with typical estimates used by others in the industry for each type of facility. (Spanos Rebuttal, p. 15, lns. 10-16). Mr. Spanos reviewed information regarding the decommissioning costs of 30 to 40 plants, excluded plants that were dissimilar to the Company's units, and determined based on this information that \$40/kW would be a reasonable estimate for the decommissioning of OG&E's steam plant. (Tr. A.M. 5/12/2016, p. 76, ln. 25 through p. 77, ln. 23 (Spanos Cross)). Mr. Spanos followed a similar process for other production plant and wind. (*Id.*).

Using industry information, as Mr. Spanos did here, is an appropriate way to establish a reasonable estimate for terminal net salvage costs. (*Id.* at p. 25, ln. 19 through p. 26, ln. 3; p. 48, lns. 7-18; p. 57, ln. 23 through p. 58, ln. 3 (Spanos Cross)). Indeed, Mr. Spanos has previously used similar estimates as a component of depreciation studies accepted by commissions in other jurisdictions. (Tr. P.M. 5/12/2016, p. 1w-56, ln. 21 through p. 1w-57, ln. 17 (Spanos Redirect)). The ALJ erred by ignoring Mr. Spanos' analysis.

The ALJ also noted that OG&E has not yet performed a site-specific decommissioning study. (ALJ Report, pp. 57-58). But, the absence of a full-blown decommissioning study is no reason to adopt an unreasonably low estimate for terminal net salvage costs now. Simply put, the actual costs of decommissioning will not be known until the work is performed. (Tr. A.M. 5/12/2016, p. 36, ln. 8 through p. 37, ln. 10 (Spanos Cross)). Any decommissioning estimates (used now or any time until decommissioning is completed) will be subject to uncertainty. (Tr. A.M. 5/17/2016, p. sd-20, lns. 4-25 (Cook Cross)). In this proceeding, there is no estimate in the record for these costs other than the estimate provided by Mr. Spanos. Moreover, to the extent those costs are not recovered now, the cost burden will be unduly shifted to future ratepayers. (Tr. A.M. 5/12/2016, p. 47, lns. 12-17 (Spanos Cross)). As Staff witness Garrett recognized, "the [C]ompany will recover all of those dollars. It's just a question of timing." (Tr. Late P.M. 5/18/2016, p. sd-75, lns. 4-5 (Garrett Redirect)).

OG&E does not dispute that a site-specific study will be useful for determining estimated decommissioning costs. But, the absence of such a study does not warrant allowing only unreasonably low levels of recovery.⁸ Thus, the ALJ's recommendation to halve OG&E's estimated recovery of production plant net salvage should be amended. The terminal net salvage costs of \$18.3 million developed by the Company are reasonable estimates, the adoption of which would benefit ratepayers by avoiding intergenerational inequity and allow the Company to systematically and rationally recover its costs.

e. Vegetation Management

⁸ Even Mr. Pous has previously recommended that a utility recover production plant net salvage based on estimates of \$30/kW for steam plant, \$8/kW for other production plant, excluding wind, and \$5/kW for wind in a 2013 case where no site-specific study had been conducted. (Tr. P.M. 5/16/2016, p. 1w-40, ln. 1-9 (Pous Cross)); Spanos Rebuttal, p. 18, lns. 1-21).

In this case, OG&E requested approximately \$30 million total company vegetation management expense level. 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. (Cassada Direct Testimony, p. 15, Ins. 25-28.) In his report, the ALJ only recommended recovery of a portion of that request based on the costs over a five year average. (ALJ Report at 49). Instead of recommending approximately \$25.8 million in distribution-related vegetation management expense and \$4.5 million in transmission-related expense, the ALJ only recommended \$21.5 million for distribution (inclusive of cycle work, non-cycle work and substation work) and approximately \$2.8 million for transmission. On page 49 of the ALJ Report, the ALJ stated his belief that those expense levels are adequate.

OG&E believes that the record demonstrates that adequate management of the vegetation around the Company's distribution and transmission system facilities requires the full amount requested. Vegetation management is directly linked to the safe and reliable delivery of electricity. OG&E believes that it is imperative for a reliable electric system that its requested vegetation management expense levels be approved.

OG&E's vegetation management witness, Jarod Cassada, OG&E's Supervisor for Vegetation Management, provided sufficient evidence for the proposed increase in expense for both distribution and transmission vegetation management. Mr. Cassada is the only witness in this cause that is both a registered Forester and Arborist with the Oklahoma Department of Agriculture, Food and Forestry, a Certified Arborist/Utility Specialist with the International Society of Arboriculture, and a Certified Pesticide Applicator with the Oklahoma Department of Agriculture. (Cassada Direct, p. 2, Ins. 14-18; Tr. A.M. 5/6/16, p. rdh-69, ln. 12 through p. rdh-70, ln. 1).

1. Distribution

For distribution vegetation management, Mr. Cassada, who is the only witness that performs vegetation management as a full time job, testified why adhering to a five year average fails to provide adequate funding for distribution vegetation management. He stated that taking an average cost over time is a faulty approach because the average includes funding levels that are too low to enable OG&E to clear circuits in a manner our customers have come to expect and regulators require. Also, Mr. Cassada stated that an average of previous years is a faulty approach that does not account for inflation, system expansion, or other changes to the system. (Cassada Rebuttal, p. 10, Ins. 5-7, 18-21.) That is, utilizing a five year average includes years when there were less line miles and outdated contractor pricing. Using such old data in the averaging process is not reflective of the true costs going forward.

Overhead distribution line miles have increased by 11% since the last rate case and 18,587 miles are subject to the four year vegetation management cycle, required by this Commission. (Cassada Direct, p. 9, Ins 3-4, 7-8). When new lines are added, OG&E need not initially perform vegetation management on those lines because construction crews perform initial vegetation clearing as part of the construction process. There needs to be time before the vegetation grows to the point of needing to be managed. That is why OG&E did not necessarily

spend the requested levels during the test year and instead asked that the Commission approve those higher expense levels for the future period.

There were a myriad of other reasons that OG&E witness Cassada testified contributed to the higher future expense levels, including heightened customer expectations related to storm response, rising contractor cost and availability, and increasing customer requests. These reasons have made it increasingly difficult to adhere to a comprehensive 4-year cycle. (Cassada Direct, p. 10, lns. 5-15 through p. 12, ln. 12). According to Witness Cassada, OG&E's requested expense level allows the Company to be less reactive in its approach to vegetation management through the implementation of a comprehensive, 4-year-cycle designed to improve reliability, manage cost and prevent outages. (Cassada Direct, p. 9, lns 13-22, p. 10, Chart 3; Cassada Rebuttal, p. 3, lns. 8-12 and p. 4, lns. 24-26; Tr. A.M. 5/6/2016, p. rdh-119, ln. 15 through rdh-120, ln. 13).

OG&E's analysis indicates that approximately \$26 million for its distribution vegetation management efforts, including \$23.4 million in distribution cycle work, \$2.1 million in distribution non-cycle work, \$360,000 in distribution substation work, will allow the Company to meet the requirements of its customers. However, should the Commission accept the ALJ's recommendation of a five year average, OG&E would request that not only the five year average for distribution cycle work (approximately \$21.5 million) but also the five year average for distribution non-cycle vegetation management of \$1,416,496 (Cassada Rebuttal Exhibit JC-2) and distribution substation work of approximately \$360,000 be authorized by the Commission.

2. Transmission

First, the ALJ mischaracterized the increase for transmission vegetation management. The ALJ stated that the increase in costs was for "herbicide treatment," but Mr. Cassada testified that the cost increases were related to all aspects of transmission vegetation management, *i.e.*, the vegetation clearing cycle and a robust inspection program. (Cassada Direct, p. 6, ln 30.)

Also, the ALJ incorrectly cited the five year average as \$2,842,153 (the actual test year amount) when the five year average for transmission is actually \$3,383,042. If the Commission decides to use the five year average for transmission expense, the total should be \$3,383,042, which accurately reflects the five year average, instead of \$2,842,153.

OG&E believes that there are significant reasons why OG&E's total transmission vegetation management expense of \$4.5 million should be approved. In the area of transmission vegetation management, there were significant reasons why OG&E included an increase in expense. There has been a 15% increase in miles of transmission lines. (Cassada Direct, p. 7, lns. 2-9). This means more miles of lines at which to manage vegetation. Also, OG&E added four new transmission substations and has expanded other existing substations. OG&E testified that stringent compliance regulations promulgated by the Federal Energy Regulatory Commission ("FERC") and enforced by the North American Electric Reliability Corporation ("NERC") require OG&E to prevent interruptions on transmission lines from vegetation. (Cassada Direct, p. 7 lns. 19-22 through p. 8, lns. 1-6).

Further, the ALJ cites to opposition from the Staff for his recommendations to disallow a portion of transmission vegetation management expense. (ALJ Report at p. 49). But, OG&E cannot find any place in the record where the Staff opposed the increase for transmission vegetation management expense. In fact, during the hearing, Staff Witness Thompson stated that he understood that OG&E had added significant miles of transmission lines and that additional transmission lines result in additional cost to inspect and maintain for vegetation management purposes. (Tr. A.M. 5/25/2016, p. sj93, lns. 5-12).

Mr. Cassada testified that the increase in line miles and associated transmission infrastructure has contributed to a need for increased spending of approximately \$1.69 million annually. It is simply not realistic to "postpone" that annual \$1.69 million in expense. As Mr. Cassada testified, the increase in line miles is a 60% increase in line miles covered under NERC FAC-003-3 and thus, these line miles have more stringent vegetation management requirements and require more land area be maintained per mile for vegetation issues (Cassada Rebuttal, p. 9, lns. 18-22; Cassada Direct p. 7, lns 7-8 and data request AG 7-11, attached as Rebuttal Exhibit JC-3). Also, in explaining the lower test year expense amount, OG&E testified that OG&E had not needed to spend this additional vegetation management expense earlier in the test year because, for the majority of the new transmission lines built, 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. Mr. Cassada testified that these new lines will now, starting in 2016, need to be maintained, resulting in the requested increase. (Cassada Rebuttal, p. 9, lns. 22-27.)

Given the increase in transmission line miles, the ongoing and stringent NERC reliability requirements, and the importance of increasing this funding now, OG&E requests that the Commission approve recovery of OG&E's total transmission vegetation management expense of \$4.5 million.

f. Fuel Adjustment Clause ("FAC")

In the non-unanimous rate design settlement that OG&E did not execute, the Stipulating Parties recommended that the approximate balance in the Company FAC be credited back to customers through a credit in the FAC beginning within 30 days after a final order and continuing for 12 months on the same basis that such fuel costs were originally collected (Joint Stipulation, Section 10, pp. 8-9). During the hearing, Mr. Rowlett 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). In the ALJ Report, the ALJ found that this provision of the non-unanimous settlement was reasonable and should be adopted.

However, OG&E has already provided that remaining credit to customers. As the Commission is aware, in January 2016, OG&E first made a significant reduction to its FAC collections in the amount of approximately \$52,021,323. This first adjustment coincided with the filing of the Company's rate case at the end of 2015. Then, after the close of the record in this proceeding, the Company further reduced its FAC collections in July 2016 by another \$21,387,832. Therefore, OG&E did not wait for the final order in this Cause and has already

adjusted its FAC to reflect any over recovery for past periods. This settlement provision should be considered moot.

g. Rate Design

With regard to certain rate design issues, OG&E seeks clarification and asks that the Commission reverse one of the ALJ's recommendations. Specifically, as discussed below, the clarifications relate to the ALJ's findings regarding the appropriate fixed customer charge. OG&E also believes that the ALJ erred in not granting the Company's relief regarding Distributed Generation tariff changes.

1. Monthly Customer Charge

There was a disagreement between OG&E and the Stipulating Parties that executed the non-unanimous settlement in this Cause with regard to the appropriate monthly customer charges. The Company wanted to increase the customer charge for various rate classes based on costs as reflected in the unit cost calculation (Wai Direct, p. 5, ln. 4 through p. 6, ln. 5), and directly corresponding to OG&E's Cost of Service Study filed in this Cause. For example, the unit cost for the residential customer component is \$26.77 on average, so OG&E wanted to increase the customer charge for R-1 customers from \$13.00 to \$26.54 per month (Wai Direct, p. 9, lns. 2-6).⁹ In its non-unanimous settlement, the Stipulating Parties stated that they believe monthly customer charges should remain unchanged. Some parties have failed to grasp that an increase in the customer charge would be coupled with a decrease in the energy charge after many of the fixed charges recovered through a higher customer charge would no longer be collected through a volumetric energy charge. (Wai Direct, p. 8, lns. 11-14). It is simply changing the method of collecting those fixed costs.

During the hearing, OG&E witness Rowlett testified that the Company believes a fair alternative between the Stipulating Parties' proposal and OG&E's proposed charges would be a monthly residential customer charge of \$20.00 and a monthly general service customer charge of \$30.00 (Tr. P.M. 5/26/2016, p. 22, ln. 18 through p. 23, ln. 10). OG&E also agreed to keep public schools, oil and gas and municipal pumping customer charges at current levels. (Tr. P.M. 5/26/2016, p. sd-23, lns. 1-5). A \$20.00 residential customer charge and a \$36.70 general service customer charge were originally proposed by Staff. (Champion Responsive, Rate Design, p. 22, ln. 10 through p. 23, ln. 3). The \$20.00 residential customer charge is consistent with the current customer charge of PSO. (Rowlett Tr. P.M. 5/26/2016, p. sd-23, lns. 6-10).

OG&E seeks clarification from the Commission because it is unclear what the final recommendation is with regard to the customer charge. The ALJ recites the positions of the parties, but never states what customer charge he is recommending. The ALJ suggests the concept of a "minimum bill," but does not elaborate as to how this concept would be

⁹ For General Service customers, the Company's change in the customer charge is based on the allocated share of customer component costs for the GS-1 service level 5 class, which is \$50.13 per customer per month. However, the Company only originally proposed a GS customer charge of \$48.50, which reflects the weighted average of the customer cost component for all GS customers. (Wai Direct, p. 11, ln. 8-11).

implemented. OG&E believes that its proposed compromise of a monthly residential customer charge of \$20.00 and a monthly general service customer charge of \$30.00 is reasonable. While OG&E believes that the customer charges should closely reflect unit costs for that particular class, the compromise position proposed by OG&E gradually takes a step in that direction.

2. Distributed Generation ("DG")

OG&E believes that the ALJ erred by not recommending the institution of demand charges for OG&E's DG customers. OG&E believes that demand charges and a three part rate structure comply with the requirements of 17 O.S. § 156. OG&E believes that it is good public policy for the Commission to ensure that customers who cannot afford private solar panels on their homes do not pay the costs that should be paid by those customers that have solar panels. Under the current two-part rate, DG customers are compensated based on the energy charge under which they are billed. Because the energy charge includes items unrelated to production such as T&D wires costs, DG customers are over compensated for their production to the detriment of other non-DG customers. (Walkingstick Rebuttal at p. 4, ln. 27 through p. 7, ln. 1). Demand charges comply with Oklahoma law by addressing this subsidy problem and ensuring that DG customers pay more of their fixed costs through a demand charge instead of a variable energy charge.

OG&E originally proposed that two separate rate classes be established for 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. The Company also requested that companion tariffs of Net Energy Billing Option- kilowatt (NEBO-kW) and the Renewable Power Purchase Option (RPPO) 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. The Company's proposed demand charge for the R-TOU-kW was \$1.78/kW and for COM-TOU-kW was \$3.94/kW. (Wai Direct, p. 27, Table 14).

OG&E witness Wai supported the Company's proposed prices of the R-TOU-kW and COM-TOU-kW DG tariffs being established at underlying functional costs for each of these proposed new DG classes of service. (Wai, Direct, p. 26, lns. 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 the Company (R-TOU-kW and COM-TOU-kW; Table 14) would generally result in lower bills than under the Company's proposed standard TOU rates (Table 5).

During the hearing, OG&E witness Rowlett testified that the Company believes that now is the time to institute demand charges for DG customers, but suggested a compromise proposal (Tr. P.M. 5/26/2016, p. sd-23, lns. 14-25). Mr. Rowlett recommended that the demand charges

be lowered from OG&E's original proposal to \$1.00 per kW for residential DG customers and \$2.00 per kW for commercial customers. (Tr. P.M. 5/26/2016, p. sd-24, lns. 3-8).

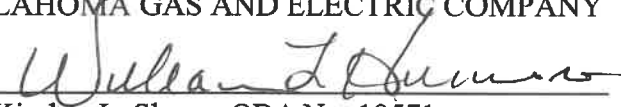
OG&E believes that its compromised proposal for a smaller demand charge should be implemented. Instead of \$1.78 per kW for R-TOU-kW and \$3.94 per kW for COM-TOU-kW, the Commission should implement \$1.00 per kW for residential DG customers and \$2.00 per kW for commercial customers. The Commission should further find that distributed generation customers currently taking service under tariffs without a demand charge, who installed distributed generation equipment after October 31, 2014, and who use some of their output to serve onsite load, are required to subscribe to either the R-TOU-kW or COM-TOU-kW tariff proposed by the Company.

WHEREFORE, OG&E requests this Commission adopt the ALJ recommendations with the few modifications discussed herein.

Respectfully submitted,

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OG&E's Exceptions to the ALJ Report
PUD 201500273

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CERTIFICATE OF SERVICE

This is to certify that on the 4th day of January, 2017, a true and correct copy of the above and foregoing motion was transmitted to the following:

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OG&E's Exceptions to the ALJ Report
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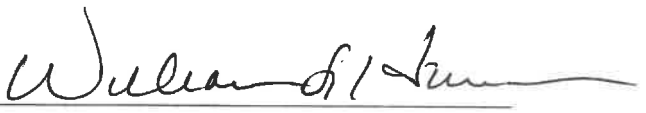
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