BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF OKLAHOMA GAS AND ELECTRIC	)	
COMPANY FOR APPROVAL OF	)	**DOCKET NO. 16-052-U**
A GENERAL CHANGE IN RATES,	)	
CHARGES AND TARIFFS	)	

SURREBUTTAL TESTIMONY

OF

MARK E. GARRETT

REVENUE REQUIREMENT ISSUES

ON BEHALF
OF

ARKANSAS RIVER VALLEY ENERGY CONSUMERS ("ARVEC")

March 30, 2017

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 50 Penn Place, 1900 N.W. Expressway, Suite 410, Oklahoma City, Oklahoma 73118.

Q: DID YOU PROVIDE REVENUE REQUIREMENT TESTIMONY ON JANUARY 31, 2017?

A: Yes.

Q: DID YOU PROVIDE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION WITH THAT TESTIMONY?

A: Yes.

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: My Surrebuttal Testimony addresses the Rebuttal Testimonies of: (1) Mr. Rowlett regarding the issue of Vegetation Management; (2) Mr. Thenmadathil regarding the issues of SERP, Storm Damage, and Incentive Compensation; (3) Ms. Ruden regarding the issue of Incentive Compensation; (4) Mr. Forbes regarding the issue of Corporate Cost Allocations; and (5) Mr. Smith regarding the jurisdictional allocation of wind assets. My Surrebuttal Testimony also addresses the Responsive Testimony of APSC Staff Witness, Mr. Eggleton.

II. SURREBUTTAL TO MR. ROWLETT

Vegetation Management

Q: WHERE DOES THE ISSUE OF VEGETATION MANAGEMENT STAND?

A: In my Direct Testimony I explained that OG&E is proposing a significant increase to its vegetation management costs. In all, OG&E is proposing an increase of $879,716 over test year levels,[1] comprised of $816,850 for distribution system costs and $62,866 for transmission system costs. This amounts to a 40% overall increase in vegetation management costs when compared to the test year level. I explained that most of the increase is in *distribution* system management costs. I noted that OG&E's test year level for distribution vegetation management costs were already 25% higher than the 2015 level and 37% higher than the 5-year average level from 2011-2015.[2] I showed how OG&E's requested level for distribution system vegetation management costs was 96% higher than the 5-year average from 2011-2015.

I further explained that all of the factors that OG&E points to as justification for the higher requested level of vegetation management costs, including higher contractor costs, NRRI requirements, more miles of line to clear and the higher costs of moving to a 4-year cycle,[3] all existed during the test year. In other words, these factors may explain why the test year costs were 37% higher than the prior 5-year average, but they do not explain why the costs would be even higher going forward.

[1] See W/P C 2-22, Updated.
[2] See OG&E response to APSC 39.01.
[3] See Direct Testimony of J. Cassada.

In my responsive testimony I also noted that it appears OG&E under-spent on its vegetation management costs in 2013 and 2014, and this could explain why OG&E is requesting even more money going forward to help make up these foregone maintenance costs. I explained that it is improper for OG&E to choose to forgo necessary maintenance expenditures in order to send more money to its shareholders – and then ask ratepayers to help "catch up" these foregone maintenance costs.

I recommended that the Commission set the vegetation management expense at the test year level, since the test year level represents a 25% increase in vegetation management costs over the 2015 level and a 37% increase over the average level for the period 2011-2015.

Q: WHAT DID THE COMPANY SAY IN RESPONSE TO YOUR DIRECT TESTIMONY?

A: In response to my testimony, Mr. Rowlett provided the following statements:

> I would only point out that witness M. Garrett's testimony is replete with errors and incorrect information. First, the Company has not requested "catch up" expense for what M. Garrett calls foregone maintenance. Second, while the Company believes that a 4-year cycle is generally the optimal cycle length, witness M. Garrett is incorrect in suggesting there is a cycle requirement in Arkansas that the Company has neglected. As explained in the Direct Testimony of Company witness Cassada, the distribution system is managed by prioritizing work based on reliability. Finally, witness M. Garrett fails to recognize that increases in vegetation management costs have been driven by a 24% increase in distribution line miles on the OG&E system a 20% increase in contractor costs, and increasing numbers of customer call outs which all serve to increase the cost of cycle maintenance.

Q: DID YOUR TESTIMONY CONTAIN ANY ERRORS OR INCORRECT INFORMATION?

A: No. The testimony contained only information provided by the Company. Moreover, Mr. Rowlett does not actually point to any specific errors or incorrect information in my Testimony. He merely concludes: (1) that the Company has not requested "catch up" expense for foregone maintenance; (2) that a 4-year cycle is generally the optimal cycle length, (3) that I was incorrect in suggesting there is a cycle requirement in Arkansas that the Company has neglected, and (4) that I failed to recognize that increases in vegetation management costs have been driven by a 24% increase in distribution line miles on the OG&E system and a 20% increase in contractor costs and increasing numbers of customer call outs.

Q: ARE THERE PROBLEMS WITH MR. ROWLETT'S ASSERTIONS?

A: Yes. First, although Mr. Rowlett argues that the Company has not requested "catch up" expense for foregone maintenance–this claim seems highly suspect in light of the fact that OG&E's expenditures in 2013 and 2014 were less than half the amount OG&E now claims it will require to adequately maintain the system. Second, the use of a 4-year vegetation management cycle is not new to OG&E. OG&E has used the 4-year cycle for many years in Oklahoma but has neglected to use the approach in Arkansas until now. By not employing that approach in Arkansas, it appears that the Company has not met its vegetation management needs on an ongoing basis. Finally, Mr. Rowlett is mistaken that I failed to recognize the factors causing the increases in vegetation management costs. In my responsive testimony I specifically addressed the factors causing the increase and I explained that all of these factors existed during the test year. I pointed out that these factors may explain why test year cost levels are higher, but they do not explain the even higher levels requested by the Company going forward.

Q: DID OG&E PROVIDE ANY INFORMATION IN ITS REBUTTAL TESTIMONY THAT WOULD EXPLAIN WHY A 37% INCREASE IN THE TEST YEAR LEVEL IS NOT ADEQUATE GOING FORWARD?

A: No. The table below demonstrates that (1) the test year level is 37% higher than the average spend in the prior years, (2) that OG&E was spending less in 2013 and 2014 then the test year level, and (3) that the requested level going forward is nearly twice what OG&E has spent in the past to provide what it claims is adequate service.

Table 1: Comparison of Distribution Only Vegetation Management Costs[4]

2011	2012	2013	2014	2015	5-Yr Avg	Test Year	Requested
1,464,681	1,622,786	1,161,686	1,199,035	1,528,794	1,395,396	1,914,689	2,731,519
Test Year Compared to 2015						25%	
Test Year Compared to 2014						60%	
Test Year Compared to 5-Year Average 2011-2015						37%	
Requested Level Compared to Test Year							43%
Requested Level Compared to 5-Year Average 2011-2015							96%

[4] Based upon data taken from OG&E's response to APSC 39.01 and OG&E's Vegetation Management Adjustment in WP C-2-22.

Q: HAS OG&E PROVIDED ANY REBUTTAL TESTIMONY THAT WOULD CHANGE YOUR RECOMMENDATION?

A: No. I still believe my recommendation to set rates based upon the significantly higher test year level should be adequate going forward. If not, it is likely due to the fact that OG&E under-spent in the 2013-2014 timeframe.

III. SURREBUTTAL TO MR. THENMADATHIL

Supplemental Executive Retirement Plan ("SERP")

Q: WHERE DOES THE SERP ISSUE STAND?

A: In my Direct Testimony I testified that the Company provides supplemental retirement plan benefits to certain highly-compensated individuals in addition to the benefits provided under the general pension plans of the company. These plans are referred to as *non-qualified* plans because they do not qualify as a deductible tax expense under the code. I recommended that SERP costs be disallowed as a matter of principle. These costs are not necessary for the provision of utility service. 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 in which not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. If SERP costs are disallowed, ratepayers will pay for all of the executive benefits included in the Company's regular pension plans, and shareholders will pay for the additional executive benefits included in the supplemental plan. I explained that many jurisdictions, including Arkansas, exclude executive supplemental benefits, understanding that these costs would be better borne by the utility shareholders. I recommended that SERP Expense Recovery be disallowed in this proceeding.

Q: DID THE COMPANY REBUT THIS TESTIMONY?

A: No. Mr. Thenmadathil does not address the adjustment on its merits; he merely asserts in his Rebuttal Testimony that "OG&E did not include SERP expense in the *pro forma* level of pension expense, therefore Mr. Garrett's adjustment to remove SERP is not necessary."[5]

Q: IS MR. THENMADATHIL CORRECT?

A: No. I don't think so. Although SERP expense is not included in the *pro forma* level of the pension expense adjustment at C-2-12, it is also not included in the test year expense side of the adjustment either. If this is the case, and SERP expense is not included on either side of the pension expense adjustment, then SERP expense remains in test year expense, and therefore must be removed through an affirmative SERP adjustment.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that if the Company cannot demonstrate that it effectively removed SERP expense from pro forma operating expense, the Commission should require that this adjustment be made.

[5] Thenmadathil at page 3.

Storm Expense

Q: WHERE DOES THE ISSUE OF STORM EXPENSE STAND?

A: In my Direct Testimony, I stated that OG&E is proposing to increase its test year storm damage costs of $372,079 by $694,635 to arrive at a 4-year average spend for storm damage costs of $1,066,714.[6] This represents a 187% increase in these costs. I said that I did not agree with this adjustment because the Company's 4-year average from 2012-2015 included an abnormally high storm cost year of 2013, where the Company incurred storm costs of $2,857,329. The average cost for the period 2012 through the test year, without the unusually high costs incurred in 2013, is $397,687, which is very consistent with the test year level.

I recommended that storm damage expense be adjusted to a 2-year average level of $518,085. A 2-year average, using 2014 and 2015, eliminates the unusually high year of 2013 and the unusually lower cost year of 2012 as well. -To set the storm damage expense level to $518,085 requires an adjustment in the amount of $(548,629). I also explained that if OG&E has another unusually high storm cost year going forward, that such cost can be addressed in its annual FRP filing.

Q: DID THE COMPANY AGREE WITH THIS ADJUSTMENT?

A: No. After reading the AG's testimony, the Company changed its position in Rebuttal Testimony from a 4-year average to a 5-year average, which resulted in materially the same adjustment. The problem with either approach though is that both the 4-year and

[6] See W/P C 2-32.

the 5-year averages include the unusually high 2013 cost levels. For ratemaking purposes, the use of prior-year cost level averaging is only appropriate if the prior year cost levels are normal levels. Abnormal events must be removed. The 2013 cost level of $2,857,329 is 7 times larger than the average cost for the period without the unusually high-cost 2013 year. The bottom line is that, for ratemaking purposes, major storm events should not be included in setting normal storm cost levels.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission either use the 2-year average that I proposed in my Direct Testimony, which results in an adjustment of $(548,629), or simply use the test year level, since the test year level is consistent with a 5-year average (2012 through the test year) without 2013. This would result in an adjustment of $(694,635) to effectively reverse OG&E's proposed adjustment.

Short-Term Incentive Teamshare Expense

Q: WHERE DOES THE ISSUE OF SHORT-TERM INCENTIVE TEAMSHARE EXPENSE NOW STAND?

A: In my Direct Testimony, I normalized test year Teamshare expense using a 2-year average of these costs which included the years 2014 and 2015. These years were consistent with actual test year levels. I did not include the higher-cost years of 2012 and 2013 in the normalization adjustment because the higher cost levels that occurred in these years were related to higher earnings per share (EPS) metrics, which would have been disallowed anyway under the financial-performance rule. After computing the normalized incentive level based upon the two year average of 2014 and 2015, the second part of my adjustment eliminated 50% of the normalized incentive level to reflect the portion of the incentive payments that are related to financial performance measures.

Q: DID MR. THENMADATHIL AGREE WITH YOUR ADJUSTMENT?

A: No. In its rebuttal testimony, the Company moved away from its 4-year average for normalizing Teamshare costs and agreed with Staff's 5-year average. The problem with both of these averages is that they include abnormally high-cost years that do not reflect ongoing levels. Further, virtually all of the higher cost levels in 2012 and 2013 were caused by higher EPS which would be excluded for ratemaking purposes anyway.

Q: DID THE COMPANY'S REBUTTAL TESTIMONY CHANGE YOUR MIND REGARDING SHORT TERM INCENTIVES?

A: No. I believe the Commission should either use my approach of a 2-year average to normalize Teamshare costs or simply use the test year levels as recommended by the AG. The Company's and Staff's averages are skewed by including the higher-cost years of 2012 and 2013, where the higher costs were solely related to excludible EPS expenses.

IV. SURREBUTTAL TO MS. RUDEN

Short-Term and Long-Term Incentives

Q: WHERE DOES THE ISSUE OF SHORT-TERM INCENTIVE EXPENSE STAND WITH RESPECT TO THE PORTION THAT SHOULD BE DISALLOWED?

A: In my Direct Testimony, I proposed to exclude 50% of the annual incentive plan expense. I said that this treatment was consistent with the treatment of these costs by this Commission in recent cases involving Entergy Arkansas.[7] My recommendation is also consistent with the recent treatment of these costs by the Oklahoma Corporation Commission for recovery of OG&E's incentive costs in that state.[8] This recommended sharing of Teamshare costs between the Company and its customers reflects the fact that a major purpose of the Teamshare payments is to increase the financial performance of the Company. I said that as a general rule, regulatory commissions exclude incentive compensation associated with financial performance. I provided a Survey of the 24 Western States that showed that this is the predominant treatment of incentive costs in those states. Staff and the AG also recommended a 50% disallowance of OG&E's short-term incentive costs.

Q: DID OG&E AGREE WITH THIS TREATMENT?

A: No. In response to intervener testimony addressing the proper treatment of these costs for ratemaking purposes, OG&E provided the testimony of an OGE Energy Corp. employee in the human resources department, Ms. Ruden. At page 3, lines 5-7, Ms.

[7] See Docket No. 13-028-U, Order No. 21, and Order No. 35 and Docket No. 15-015-U, Order No. 18.
[8] See Oklahoma Corporation Commission Final Order issued in Cause No. PUD 201500273.

Ruden testifies that she is "providing rebuttal testimony to substantiate the costs and design structure of OG&E's compensation plans as reasonable and support OG&E's position that the recovery of the full amounts of these costs is appropriate." While it seems appropriate for Ms. Ruden to substantiate the costs and design structure of OG&E's compensation plans as reasonable – which is not an issue here – it would not be appropriate for Ms. Ruden to provide expert testimony regarding the recovery of these costs for ratemaking purposes. Ms. Ruden is not a ratemaking expert. This means the Company has essentially provided no expert testimony to rebut the positions taken by ARVEC, Staff and the AG regarding the ratemaking treatment of OG&E's short-term incentive costs.

Q: DID OG&E PROVIDE ANY EXPERT WITNESS TESTIMONY REGARDING HOW THESE COSTS SHOULD BE TREATED FOR RATEMAKING PURPOSES, EITHER IN DIRECT OR REBUTTAL TESTIMONY?

A: No. The Company only provided the testimony of accounting witness, Mr. Thenmadathil, regarding the normalization of the test year expenses level, but provided no testimony to support the inclusion of these costs in rates.

Q: IS THE SAME TRUE FOR LONG-TERM INCENTIVE EXPENSE?

A: Yes.

V. SURREBUTTAL TO MR. FORBES

Corporate Cost Allocation

Q: WHAT IS THE STATUS OF THE CORPORATE COST ALLOCATION ISSUE?

A: In my Direct Testimony, I explained that OG&E is proposing to increase rates by $3,737,315 for costs the Holding Company will no longer be able to allocate to Enable Midstream Partners, because Enable is a stand-alone company providing these services for itself now. These costs include costs for central functions such as Accounting, Human Resources and Information Technology. I pointed out that these costs are costs of the parent company (OGE Energy Corporation) that are being allocated to its two affiliates, OG&E and Enable. Beginning in 2016, OGE Energy Corporation will no longer be able to allocate these costs to Enable. Thus, going forward, it plans to allocate all of the costs to OG&E instead.

I said I did not agree with this treatment for several reasons. 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 Corp proposes to allocate to OG&E may be the type of costs that are necessary for the provision of electric service, but the amount is not a reasonable amount for OG&E. The reasonable amount of these costs allocable to OG&E is the amount the Company was paying when some of the costs were being allocated to Enable. 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. I also explained that if these costs are included in rates, OGE Energy will have little incentive to operate its business in such a way as to reduce or eliminate these excess costs. The bottom line is that these costs are the responsibility of OGE Energy Corp., the parent company, not OG&E, the utility.

Q: DID THE COMPANY AGREE WITH THIS POSITION?

A: No. OG&E provided the testimony of Mr. Forbes who testified (1) that administrative costs are "necessary and integral to the operations of a publicly-traded company such as OG&E" and are appropriately allocated costs; (2) that I failed to provide specific evidence that OG&E was operating in an imprudent manner; (3) that there are no excess costs to eliminate since these are fixed costs that cannot be reduced; and (4) that it "was inappropriate and unfair to deny the Company recovery of necessary administrative costs simply because OGE Energy has provided a benefit to customers for the last thirty years by offsetting a portion of fixed administrative costs, but is unable to continue to do so."

Q: DO YOU AGREE WITH ANY OF THESE POINTS?

A: No. Mr. Forbes' first assertion is particularly telling. He attempts to make the point that administrative costs are necessary costs – which is somewhat superfluous because no one disagrees – in doing so, however, he refers to OG&E as a publically-traded company, which it is not. OGE Energy Corp., the parent, is the publically-traded company, not OG&E. Mr. Forbes, of course, knows this and his statement was just a mistake. But, his statement is revealing as to management's attitudes toward OG&E.

Mr. Forbes' second point – his claim that I failed to provide evidence that the costs were imprudently incurred – is similarly irrelevant. The costs may be prudently incurred by the parent company, OG&E Energy Corp., but they are not appropriately allocated to OG&E, merely because Enable is no longer willing to pay them. Moreover, these are affiliate costs, and there is no presumption of prudence that attaches to these costs. It is OG&E's burden to show that the costs are prudent, in both necessity and amount. It is not the intervener's responsibility to show that the costs are imprudent.

Mr. Forbes' third point – that there are no excess costs to reduce because the costs are fixed information technology costs that cannot be eliminated – also misses the point. The point is that OGE Energy will have no incentive to reduce these costs – which is what would be required in the competitive markets – if it can merely reassign these costs to OG&E. Since the Commission serves as the surrogate for competition, it should require OG&E to act in a manner consistent with the markets, where companies cannot simply raise prices to accommodate costs that affiliates no longer want to pay.

Finally, as to Mr. Forbes' fourth point, I am not recommending exclusion of these costs "simply because OGE Energy has provided a benefit to customers for the last thirty years by offsetting a portion of fixed administrative costs, but is unable to continue to do so." I am recommending exclusion of the costs because they were incurred in large part to serve Enable not OG&E. Moreover, OGE Energy Corp. will have no incentive to reduce these costs if it can simply transfer the costs to OG&E.

VI. SURREBUTTAL TO MR. SMITH

Jurisdictional Allocation of Wind Costs

Q: WHAT IS THE STATUS OF THE ISSUE REGARDING THE JURISDICTIONAL ALLOCATION OF WIND COSTS?

A: In his Direct Testimony, ARVEC witness Dr. Blank explained how OG&E used a different allocation of wind asset costs in Oklahoma and Arkansas. OG&E's jurisdictional allocation of wind in Arkansas allocates far more costs to the Arkansas jurisdiction.

Q: DID OG&E CORRECT THIS ERROR IN ITS REBUTTAL TESTIMONY?

A: No. Strangely enough, in rebuttal testimony OG&E doubles down on its misallocation of these costs. In effect, OG&E is attempting to over-collect in Arkansas, even after the error was pointed out.

Q: WHAT DOES MR. SMITH SAY ABOUT DR. BLANK'S TESTIMONY?

A: He states that "Dr. Blank is confused, [sic] he disregards that the Commission has previously decided that wind assets should be allocated on energy, not demand."[9] What he is referring to is the *customer class allocation* of the wind assets, not the jurisdictional allocation. For customer class allocations, it may be acceptable for Oklahoma and Arkansas to allocate costs to the classes in a different manner. It is not appropriate, however, to allocate these costs in a different manner for the jurisdictional allocation. OG&E's simultaneous use of different allocators in each state effectively allocates more costs to the Arkansas jurisdiction than there are costs left to collect, resulting in the Company's over-collection of wind asset costs. OG&E used a demand allocator for its jurisdictional allocation of wind assets in Oklahoma and simultaneously used an energy allocator for the Arkansas jurisdiction. The bottom line is that OG&E has over-recovered and will continue to over-recover in Arkansas if the Company is allowed to use a different jurisdictional allocation that allocates more costs to Arkansas, as the energy allocator does.

VII. SURREBUTTAL TO MR. EGGLETON

Corporate Cost Allocation

Q: WHAT TESTIMONY DID STAFF WITNESS EGGLETON PROVIDE IN RESPONSE TO OG&E'S REQUEST TO TRANSFER ENABLE COSTS TO OG&E GOING FORWARD?

A: Mr. Eggleton merely takes the Company's position on this issue. He tweaks the Company's number slightly for updated information, but provides no substantive analysis as to why, from a ratemaking perspective, these costs should now be the responsibility of OG&E's ratepayers. Since we already have the Company's perspective, his testimony doesn't really add anything of value to the discussion.

Q: DID MR. EGGLETON PROVIDE ANY ANALYSIS TO SUPPORT HIS POSITION?

[9] Smith Rebuttal Testimony at page 3, lines 11-12.

A: No. He simply agrees with the Company that OG&E should pick up these costs going forward. At a minimum, Staff should want to know (1) what these costs are, (2) whether these costs are all recoverable costs from a regulated utility, (3) what the market value of these costs is, since for ratemaking purposes, a utility should only pay the lower of cost or market for affiliate transaction costs, (4) how have these costs been reduced since OGE Energy first learned that Enable would no longer be sharing the costs after 2016, (5) how much more will the Company be able to reduce these costs in the future, (6) why is OGE Energy maintaining the added costs of a holding company when it has only one affiliate, OG&E, and (7) how much money could be saved if OGE Energy eliminated duplicated executive positions at the holding company.

Storm Expense

Q: WHAT TESTIMONY DID STAFF WITNESS EGGLETON PROVIDE REGARDING OG&E'S STORM DAMAGE COSTS?

A: Again, Mr. Eggleton merely takes the Company's position on this issue. He tweaks the Company's number slightly for updated information, but provides no substantive analysis as to why a 4-year average of these costs is the appropriate level going forward. Again, since we already have the Company's perspective on this issue, his testimony adds little value to the discussion.

Q: DO YOU AGREE WITH HIS POSITION?

A: No. As I stated earlier, the problem with a 4-year average is that it includes the unusually high 2013 cost level. For ratemaking purposes, the use of prior-year cost level averaging is only appropriate if the prior year cost levels are normal levels. Abnormal events must be removed. The 2013 cost level of $2,857,329 was 7 times larger than the average cost for the period without the unusually high-cost 2013 year. The bottom line is that, for ratemaking purposes, major storm events should not be included in setting normal storm cost levels. Moreover, for ratemaking purposes, regulated utilities are almost always allowed to seek redress for major storm events. This treatment for major storm events is why the storm level expense built into rates should not include the costs of major storm events. This is especially true for OG&E. With an annual FRP review going forward, OG&E will be able to address the costs of an unusual catastrophic event such as a major storm in its annual filing.

Vegetation Management Expense

Q: WHAT TESTIMONY DID STAFF WITNESS EGGLETON PROVIDE REGARDING OG&E'S VEGETATION MANAGEMENT COSTS?

A: Once again, Mr. Eggleton accepts the Company's position on this issue, but provides no substantive analysis as to why OG&E's vegetation management will cost almost twice as much going forward. Mr. Eggleton accepts OG&E's recommendation that it move to a 4-year cycle in Arkansas but provides no analysis to determine why a 4-year cycle will costs twice as much as the approach used by OG&E in the past.

Q: DO YOU AGREE WITH HIS RECOMMENDATION?

A: No. Since the test year costs were 25% higher than 2015 and 60% higher than 2014, and since all of the factors identified by OG&E to support its higher requested level for these costs existed in the test years, the test year level should be adequate going forward. If not, OG&E will have the benefit of its annual FRP review where any higher vegetation management costs, should they develop, may be considered for recovery in rates.

VII. ARVEC'S SURREBUTTAL REVENUE REQUIREMENT

Q: HAVE YOU UPDATED ARVEC'S REVENUE REQUIREMENT RECOMMENDATION BASED ON THE COMPANY'S REBUTTAL TESTIMONY?

A: Yes. Based on OG&E's rebuttal testimony, I made several changes to Direct Exhibit MG-2 where ARVEC's revenue requirement calculations were set forth. The following changes are incorporated in my Surrebuttal Exhibit MG-2:

1. Changed the revenue deficiency, our starting point, to OG&E's rebuttal position;
2. Updated the Enable adjustment to use OG&E's rebuttal adjustment;
3. Updated Storm Damage to use OG&E's rebuttal adjustment;
4. Updated Vegetation Management to use OG&E's rebuttal adjustment;
5. Removed ARVEC's proposed Ad Valorem Tax adjustment;
6. Corrected ARVEC's jurisdictional Depreciation Expense calculations;
7. Calculated a new revenue excess of $(1,380,079).

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

CERTIFICATE OF SERVICE

I, Thomas P. Schroedter, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail this 30th day of March 2017.

Thomas P. Schroedter

SURREBUTTAL EXHIBIT MG 2.12

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - SUMMARY OF PROPOSED ADJUSTMENTS
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Ln	Descriptions	Witness	Ref.		Rate Base Items	ROR W/Tax	Arkansas Impact
1	**OG&E Proposed Rate Increase**		Sch. A				**$ 15,028,645**
2	**Pro Forma Rate Base and Adjustments**				$ 529,153,916		
3	To Adjust Jurisdictional Wind Asset Allocation	M. Garrett	MG 2.1		(13,359,341)	8.652%	(1,155,795)
4	Total Rate Base Adjustments				$ (13,359,341)		$ (1,155,795)
5	**Cost of Capital**						
6	To Adjust Return on Equity to	M. Garrett	MG 2.12	9.000%	$ 515,794,575	-0.814%	$ (4,196,323)
7	To Adjust Equity % in Capital Structure to			48.000%		-0.358%	$ (1,845,869)
8	Total Cost of Capital Adjustments						$ (6,042,192)
9	**Revenue and Expense Adjustments**						
					ARVEC Direct		
10	To Remove 50% of Annual Incentive Plan	M. Garrett	MG 2.2				(859,747)
11	To Remove Payroll Tax on Annual Plan	M. Garrett	MG 2.2				(63,363)
12	To Remove 100% of Executive Incentive Plan	M. Garrett	MG 2.3				(576,054)
13	To Remove Payroll Tax Executive Incentive Plan	M. Garrett	MG 2.3				(42,455)
14	To Remove Supplemental Executive Retirement Plan	M. Garrett	MG 2.4				(181,344)
15	To Adjust OG&E Payroll	M. Garrett	MG 2.5				(303,426)
16	To Adjust Payroll Taxes	M. Garrett	MG 2.5				(22,363)
17	To Adjust Affiliate Expense Allocation	M. Garrett	MG 2.6		(364,347)		**(376,994)**
18	To Adjust OG&E Estimated Ad Valorem	M. Garrett	MG 2.7		(316,156)		-
19	To Adjust Rate Case Expense	M. Garrett	MG 2.8				(156,000)
20	To Adjust Storm Damage Expense	M. Garrett	MG 2.9		(548,629)		**(490,619)**
21	To Limit Vegetation Management to 45% Increase	M. Garrett	MG 2.10		(879,716)		**(874,926)**
22	Total Operating Revenue & Expense Adjustments						$ (3,947,291)
23	**Depreciation and Amortization Expense Adjustments**						
25	To Adjust Depreciation Rates	D. Garrett			(4,525,292)		$ (3,510,352)
24	To Reverse OG&E Restatement of 1986 Depreciation Costs	M. Garrett	MG 2.11				(525,198)
26	Total Depreciation and Amortization Expense Adjustments						$ (4,035,550)
27	**Jurisdictional Mis-Allocation of Wind Production Costs**						
28	To Adjust Jurisdictional Wind Allocation O&M	L. Blank	MG 2.1				(287,428)
29	To Adjust Jurisdictional Wind Allocation Taxes-Other	L. Blank	MG 2.1				(242,241)
30	To Adjust Jurisdictional Wind Allocation Depreciation	L. Blank	MG 2.1				(698,227)
31	Total Jurisdictional Wind Allocation Expense Adjustments						$ (1,227,896)
32	**Total ARVEC Adjustments**						$ (16,408,724)
33	**Rate Decrease after ARVEC Adjustments**						**$ (1,380,079)**

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - ADJUSTMENTS TO WIND ASSET ALLOCATIONS
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line No.	Description	Ref.	Rate Base	%	Amounts
				[Sch B-2] MG 2.12	
1	Jurisdictional Wind Asset Allocation in Rate Base	Dr. Larry Blank	(13,359,341)	8.652%	$ (1,155,795)
2	To Adjust Jurisdictional Wind Allocation O&M				(287,428)
3	To Adjust Jurisdictional Wind Allocation Taxes-Other				(242,241)
4	To Adjust Jurisdictional Wind Allocation Depreciation				(698,227)
5	Sub-Total Jurisdictional Wind Allocation Expense Adjustments				$ (1,227,896)
6	**ARVEC Total Wind Asset Allocation Adjustment**				**$ (2,383,691)**

OKLAHOMA GAS AND ELECTRIC COMPANY
ARVEC WORKPAPERS - PRO FORMA ADJUSTMENT -TEAMSHARE
Pro Forma Test Year Ending JUNE 30, 2017
DOCKET NO. 16-052-U

Description	Source	Actual Test Year	Pro Forma Year Payroll (4 yr. Avg.)(a)		$ Increase
OG&E Proposed Payroll - Source: WP C2-37					
Holding Company Team Share	WP C 2-37	$4,407,402	$6,151,292	(a)	$1,743,890
% Expensed	WP C 2-16			(b)	77.75%
Pro Forma Adjustment					$ 1,355,875
Utility Teamshare	WP C 2-37	$9,304,421	$12,728,936	(a)	$ 3,424,515
% Expensed	WP C 2-16			(b)	65.91%
Pro Forma Adjustment		$13,711,823	$18,880,228		$ 2,257,098
Pro Forma Adjustment TeamShare					$ 3,612,972
Payroll Tax %	WP C 2-17				7.37%
Payroll Tax Adjustment					$ 266,276

(a) Pro Forma Year Amounts are based on 4 Year Average (2012 - 2015 payout)
(b) 4 year Average O&M percentage (2012 - 2015) [WP C 2-16]

Source:
APSC 48.01
Teamshare History 2004-TY June 2016.xlsx

Yearly TeamShare Pay out By GL Account	Utility	Holding CO.	
2006	9,665,933	5,600,865	
2007	10,379,862	6,607,032	
2008	8,504,692	3,571,317	
2009	12,501,137	7,353,100	
2010	7,766,621	4,517,514	
2011	13,193,169	7,132,262	
2012	19,028,150	8,214,658	
2013	15,757,474	7,667,596	
2014	8,358,442	4,802,514	
2015	7,771,678	3,920,401	
Test Year	7,492,854	3,666,176	
4 YR Average	12,728,936	6,151,292	<- Avg. 2012-2015 proposed by OG&E
2 YR Average	8,065,060	4,361,458	<- Avg. 2014-2015 proposed by ARVEC

ARVEC Proposed Payroll (as Adjusted)	Pro Forma Year Payroll (4 yr. Avg.)	Two Year Average	Adjustment to Two Year Average	Adjustment to Share the Cost of STI	ARVEC TOTAL ADJ.
				50.0%	
Holding Company Team Share (from above)	$6,151,292	$ 4,361,458	($1,789,835)	($2,180,729)	
% Expensed [WP C 2-16]			77.75%	77.75%	
Pro Forma Adjustment			$ (1,391,596)	$ (1,695,517)	$ (3,087,113)
Utility Teamshare	$12,728,936	$ 8,065,060	($4,663,876)	($4,032,530)	
% Expensed			65.91%	65.91%	
Pro Forma Adjustment			$ (3,073,961)	$ (2,657,840)	$ (5,731,801)
Pro Forma Adjustment TeamShare		$ 12,426,517.48	**$ (4,465,557)**	**$ (4,353,357)**	**$ (8,818,914)**
Arkansas Jurisdictional (O&M%)			9.74890%	9.74890%	9.74890%
ARVEC ADJUSTMENT TO SHORT TERM INCENTIVES			**$ (435,343)**	**$ (424,404)**	**$ (859,747)**
Payroll Tax % [WP C 2-17]			7.37%	7.37%	
Payroll Tax Adjustment			**$ (329,112)**	**$ (320,842)**	**$ (649,954)**
Arkansas Jurisdictional (O&M%)			9.74890%	9.74890%	9.74890%
ARVEC ADJUSTMENT PAYROLL TAXES ON SHORT TERM INCENTIVES			**$ (32,085)**	**$ (31,279)**	**$ (63,363)**
Total Adjustment					**$ (923,110)**

OKLAHOMA GAS AND ELECTRIC COMPANY
PRO FORMA ADJUSTMENT - LONG TERM INCENTIVES
TEST YEAR ENDING JUNE 30, 2016
DOCKET NO. 16-052-U

Description	Actual Test Year	Pro Forma Year Payroll (4 yr. average)(a)			$ Increase
Holding Company LTI [WP C 2-38]	$4,149,770.46	$5,334,421	(a)	$	1,184,651
% Expensed			(b)		77.75%
Pro Forma Adjustment				$	921,066
Utility LTI	$2,560,643.33	$2,672,430	(a)	$	111,787
% Expensed			(b)		65.91%
Pro Forma Adjustment	$6,710,413.79	$8,006,851.00		$	73,679
Pro Forma Adjustment LTI				$	994,745
Payroll Tax %					7.37%
Payroll Tax Adjustment				$	73,313

(a) Pro Forma Year Amounts are based on 4 Year average (2012 - 2015 payout)
(b) 4 year average O&M percentage (2012 - 2015)

ARVEC Adjustments to Remove Long Term Incentive Compensation

Holding Company LTI [WP C 2-38]	$	(5,334,421)
% Expensed		77.75%
Pro Forma Adjustment	$	(4,147,512)
Utility LTI	$	(2,672,430)
% Expensed		65.91%
Pro Forma Adjustment		($1,761,399)
Pro Forma LONG TERM INCENTIVES	**$**	**(5,908,911)**
Arkansas Jurisdictional (O&M%)		9.74890%
ARVEC ADJUSTMENT TO REMOVE PRO FORMA LT INCENTIVES	**$**	**(576,054)**
Payroll Tax %		7.37%
Payroll Tax Adjustment	**$**	**(435,487)**
Arkansas Jurisdictional (O&M%)		9.74890%
ARVEC ADJUSTMENT TO REMOVE PAYROLL TAX ON LT INCENTIVES	**$**	**(42,455)**

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - ADJUSTMENT TO SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN EXPENSE
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line No.	Description	OGE Parent Holding Co.	OG&E Utility Co.	Ref.	Total
1	Supplemental Executive Retirement Plan Costs	$ 1,642,899	$ 217,248	AG 2-34_Att	$ 1,860,147
2	Expense %				100.00%
3	Total Company SERP in Cost of Service				$ 1,860,147
4	ARVEC Adjustment to Remove SERP Expense				$ (1,860,147)
5	Arkansas Jurisdictional %				9.748899%
6	ARVEC Adjustment to Remove SERP Expense				**$ (181,344)**

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - ADJUSTMENT TO OG&E'S PRO FORMA PAYROLL EXPENSE
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line No.	Description	Projected TY Total Payroll 6/30/2016	Increase Factor	Total Adjusted Payroll 6/30/2017	Difference	Arkansas Juris. % (O&M%)	Arkansas Amount
	HOLDING COMPANY						
	Source: WP C 2-16						
1	Payroll	$ 41,576,648	1.0068	$ 41,859,369			
2	Overtime	732,255	1.0068	737,234			
3	Sub Total Labor Costs - HOLDING COMPANY	$ 42,308,903		$ 42,731,992	$ 423,089		
4	4 year average O&M percent				77.75%		
5	Holding Company payroll allocated to Utility increase				$ 328,952		
	UTILITY						
6	Payroll	$ 155,668,604	1.0078	$ 156,882,819			
7	Overtime	18,325,304	1.0078	18,468,241			
8	Total Labor Costs	$ 173,993,908		$ 175,351,060	$ 1,357,152		
9	4 year average O&M percent				65.91%		
10	Percent of Utility increase O&M				$894,499		
11	Less partners share from RB/MC	(2,297,903)	1.0078	(2,315,827)	(17,924)		
12	Total O&M Salaries and Wages Less Partners Share				$ 876,576		
13	**ARVEC Proposed Increase to Test-Year Operating Expenses**				**$ 1,205,527**	9.74890%	$ 117,526
14	OG&E's updated proposed increase to payroll expense				4,317,943	9.74890%	420,952
15	**ARVEC adjustment to OG&E's requested payroll expense**				**$ (3,112,416)**	9.74890%	**$ (303,426)**
16	Payroll tax effective rate (from WP C 2-17)				7.37%		7.37%
17	**ARVEC adjustment to payroll taxes**				**$ (229,385)**	9.74890%	**$ (22,363)**
18	**ARVEC Total adjustment to OG&E's payroll expense**				**$ (3,341,801)**		**$ (325,789)**

OKLAHOMA GAS & ELECTRIC CO
ARVEC WORKPAPERS - Affiliate Expense Adjustment
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

PRO FORMA ADJUSTMENT - ENABLE REIMBURSEMENT
UPDATED FOR ACTUALS TEST YEAR ENDING JUNE 30, 2016

Line No.	Description	Source	Projected Test Year	Pro Forma Jun 16 - Jul 17	Total Co. Adjustment	Arkansas Juris %	Arkansas Jurisdiction Amount
1	OGE Corporate Services	WP C 2-39	140,530,844	140,530,844			
2	Reimbursement from Enable		9,251,798	4,764,552	$ 4,487,246		
3	Increase to Utility				$ (4,487,246)		
4	Increase to Utility (O&M Only)* (OG&E Adjustment Based on Overhead allocations to O&M based on the Test Year forecast ratio)				$ 3,737,315	9.74890%	**$ 364,347**
5	**ARVEC Adjustment to Affiliate Expense** To reverse OG&E Increases to Affiliate Expense for Enable Costs.						**$ (364,347)**
			OGE Rebuttal Position	$ 4,643,005	$ (3,867,043)	9.74890%	**$ (376,994)**

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - ADJUSTMENT TO AD VALOREM TAXES
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

SOURCE: WP C 2-29

Line No.	Description	Fair Cash Value	Assessment Ratio	Assessed Valuation	Millage Rate	% Change in Millage Rate	Historical & Proposed Tax	
1	Oklahoma:							
2	2011	2,891,390,045	22.85%	660,682,625	0.09291	2.35%	61,381,288.00	
3	2012	3,095,058,622	22.85%	707,220,895	0.09273	-0.19%	65,578,802.00	
4	2013	3,382,312,471	22.85%	772,858,400	0.09211	-0.67%	71,021,467.00	
5	2014	3,374,513,154	22.85%	771,076,256	0.09263	0.56%	71,421,089.00	
6	2015	3,575,713,218	22.85%	817,050,470	0.09259	-0.04%	75,666,951.00	
7	2016 estimated	3,468,723,896	22.85%	792,603,410	0.09259	0.00%	73,387,150.00	
							Avg % increase	3.00%
8	Arkansas:							
9	2011	230,625,000	20.00%	46,125,000	0.04935	-0.52%	2,276,360.00	
10	2012	254,350,000	20.00%	50,870,000	0.04923	-0.24%	2,504,141.00	
11	2013	279,300,000	20.00%	55,860,000	0.04965	0.85%	2,773,491.00	
12	2014	307,500,000	20.00%	61,500,000	0.04949	-0.32%	3,043,821.00	
13	2015	309,145,000	20.00%	61,829,000	0.05011	1.25%	3,098,251.00	
14	2016 estimated	324,602,250	20.00%	65,000,000	0.05011	0.00%	3,257,150.00	
							Avg % increase	7.50%
15	Total Requested Ad Valorem Tax for Pro forma year (Line 7+ 14)						**$ 76,644,300.00**	
16	Plus Adjustments:							
17	Average Increases in Valuation & Millages due to operating income & plant growth						2,445,901	
18	Total Adjustments						2,445,901	
19	Total Requested Ad Valorem Tax (Line 15 + 18)						$ 79,090,201	
20	Ad Valorem Tax for Test Year (per books)	FERC Form 1 Pg. 263 Col. i ln. 28 & 34					75,847,205	
21	Less McClain Amortization C 2-31						-	
22	Adj. Test Year						75,847,205	
23	OG&E Pro Forma Adjustment # 29				408.1		$ 3,242,996	
24	**ARVEC Adjustment to Ad Valorem Taxes (Total Company)**						$ (3,242,996)	
25	**Arkansas Jurisdictional (O&M%)**						9.74890%	
26	**ARVEC Adjustment to Ad Valorem Taxes**						**$ (316,156)**	

To reverse OG&E's increases to ad valorem taxes for estimated amounts not known and measurable.

OKLAHOMA GAS & ELECTRIC CO
ARVEC WORKPAPERS - PRO FORMA ADJUSTMENT TO REGULATORY EXPENSE
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line No.	Description	Account	Ref.	Adjustment
1	Estimated Rate Case Expenses	928	WP C 2-18-3	$ 520,000
2	Pro Forma Adjustment - OG&E proposed 2 year Amortization			260,000
3	Estimated Rate Case Expenses	928	WP C 2-18-3	$ 520,000
4	Pro Forma Adjustment - ARVEC proposed 5 year Amortization			104,000
5	**ARVEC Adjustment to Amortize Regulatory Expense over 5 Years**			**$ (156,000)**

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - ADJUSTMENT TO STORM COST RECOVERY
Pro Forma Test Year Ended June 30,2017
Docket No. 16-052-U

Line No.	Description	Source: OG&E WP C 2-32	Reference		Test Year Jun 30 2016
1	Total Company Storm Cost (less OK Storm in Reg Asset)		WP C 2-32-2		3,248,064
2	Remove Ok Storm Cost		WP C 2-32-2		(2,739,341)
3	Arkansas Test Year Direct Assigned		WP C 2-32-2		372,079
4	Arkansas 4 Year Average		WP C 2-32-3a		1,066,714
5	Adjustment to Arkansas Storms		WP C 2-32-3a		694,635
	Adjustment by FERC				
	Distribution		WP C 2-32-3a	FERC Account	
	Power Supply			593	707,627
	Substations - Distribution			513	(7,344)
	Substations - Transmission			592	8,047
	Transmission			570	(8,744)
	Total			571	(4,951)
					694,635

OG&E Adjustment:
To direct assign Arkansas storm costs for the cost of service model and to increase storm costs to a 4-year average.

Source: WP C 2-32-3a ARKANSAS STORM	Test Year	2015	2014	2013	2012	4 Year AVERAGE
AR Distribution Lines	$ 206,153	$ 437,028	$ 496,627	$ 2,777,813	$ 178,407	$ 979,405
OK & AR Power Supply	81,204	53,023	2,893	21,565	(728)	39,671
AR Substations - Dist.	3,068	6,100	5,849	29,518	42	11,134
OK & AR Substations - Tran	41,530	13,867	789	12,431	1,064	17,154
OK & AR Transmission	41,405	16,884	3,110	16,002	2,432	19,350
Total AR	$ 373,360	$ 526,902	$ 509,268	$ 2,857,329	$ 181,217	$ 1,066,714

ARKANSAS STORM	2015	2014	2 Year AVERAGE
AR Distribution Lines	$ 437,028	$ 496,627	466,828
OK & AR Power Supply	53,023	2,893	27,958
AR Substations - Dist.	6,100	5,849	5,975
OK & AR Substations - Tran	13,867	789	7,328
OK & AR Transmission	16,884	3,110	9,997
Total AR	$ 526,902	$ 509,268	518,085

			OGE Rebuttal
Arkansas Test Year Direct Assigned	WP C 2-32-2	372,079	
Arkansas 2 Year Average	(See Above)	518,085	
ARVEC Adjustment To Increase Test Year to 2 Year Average		146,006	146,006
Company's Adjustment Amount		694,635	636,625
ARVEC Adjustment to remove Excess Storm Damage Costs		**(548,629)**	**(490,619)**

OKLAHOMA GAS & ELECTRIC CO
ARVEC WORKPAPERS - ADJUSTMENT FOR VEGETATION MANAGEMENT
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line No.	Source: WP C 2-22 Description	FERC Account	**July - Dec 2015** Test Year Actual	Jan - Jun 2016 Test Year Actual	Total Test Year Amount
1	OK Vegetation Mgmt. costs Distribution Cycle	593	8,464,012	$ 8,248,597	$ 16,712,609
2	OK Vegetation Mgmt. costs Distribution Non-Cycle	593	1,516,917	718,394	2,235,311
3	OK Vegetation Mgmt. costs Distribution- System H	593	0	-	-
4	OK Vegetation Mgmt. costs Distribution Subs	592	578,478	134,450	712,928
5	OK Vegetation Mgmt. costs Transmission Lines/Su	570/571	2,444,412	1,213,095	3,657,507
6	Oklahoma Vegetation Mgmt. TYE 6/2016	Various	13,003,819	10,314,536	$ 23,318,355
7	**AR Vegetation Mgmt. costs Distribution Cycle**	**593**	**665,846**	**596,355**	**$ 1,262,201**
8	AR Vegetation Mgmt. costs Distribution Non-Cycle	593	407,750	145,245	552,995
9	AR Vegetation Mgmt. costs Transmission	570/571	175,193	86,944	262,137
10	AR Vegetation Mgmt. costs Distribution Subs	592	55,076	44,397	99,473
11	**Arkansas Vegetation Mgmt. TYE 6/2016**	Various	**1,303,865**	**872,941**	**$ 2,176,806**
12	Total Vegetation Management Cost	Various			**$ 25,495,161**
13	AR Vegetation Mgmt. costs Distribution Cycle	593			2,528,693
14	AR Vegetation Mgmt. costs Distribution Non-Cycle	593			103,171
15	AR Vegetation Mgmt. costs Transmission	570/571			325,003
16	AR Vegetation Mgmt. costs Distribution Subs	592			99,655
17	Total 4 Yr. Cycle Ave	Various			3,056,522
18	AR Vegetation Mgmt. costs Distribution Cycle	593			1,266,492
19	AR Vegetation Mgmt. costs Distribution Non-Cycle	593			(449,824)
20	AR Vegetation Mgmt. costs Transmission	570/571			62,866
21	AR Vegetation Mgmt. costs Distribution Subs	592			182
23	Pro Forma Adjustment # 22				**$ 879,716**

OG&E's proposed adjustment to increase Vegetation Management expenses for the Arkansas jurisdiction to a 4-year cycle.

ARVEC Adjustment to Remove OG&E Increase to Vegetation Management Expense **$ (879,716)**

Eliminate OGE Rebuttal Position **$ (874,926)**

Table: OG&E's Test Year Veg Mgt Expense Compared to Prior Years and OG&E Requested Level Compared to Prior Years

	Distr. Only 2011	Distr. Only 2012	Distr. Only 2013	Distr. Only 2014	Distr. Only 2015	Distr. Only Test Year	Distr. Only Requested Level
	[APSC39.01]	**[APSC39.01]**	**[APSC39.01]**	**[APSC39.01]**	**[APSC39.01]**	**[2,176,806-262,137] (above)**	**[3,056,522-325003] (above)**
	$ 1,464,681	$ 1,622,786	$ 1,161,686	$ 1,199,035	$ 1,528,794	$ 1,914,669	2,731,519
5-Year Average 2011-2015					$ 1,395,396		
Test Year Compared to 2015						25%	
Test Year Compared to 2014						60%	
Test Year Level Compared to 5-Year Average 2011-2015						37%	
Requested Level Compared to Test Year							43%
Requested Level Compared to 5-Year Average 2011-2015							96%

OKLAHOMA GAS & ELECTRIC CO
ARVEC WORKPAPERS - ADJUSTMENT TO REMOVE OG&E'S ACCUMULATED DEPRECIATION DIFFERENTIAL ADJ.
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Line	Description	Reference		Amount	
	Source: WP C 2-40				
1	Accumulated Depreciation (1986-2006)	WP B 2-5	$	31,657,965	
2	Accumulated Depreciation (2011-2017)	WP B 2-7		(97,561,704)	
3	Net reduction to Accumulated Depreciation		$	(65,903,739)	
4	Total Company Amortization		$	65,903,739	
5	Amortization Period			10	
6	Amortization Amount		$	6,590,374	
7	**Arkansas Jurisdiction**				
8	Total Company Depreciation Expense to Amortize		$	65,903,739	
9	Amortization Period			10	
10	Total Co. Amortization Amount		$	6,590,374	
11	AR Jurisdictional %			7.97%	
12	Arkansas Direct assigned Amortization		$	525,198	1
13	**ARVEC Adjustment**		**$**	**(525,198)**	
	To remove OG&E Increase to Arkansas Accumulated Depreciation				

Note: OG&E's Updated WP C 2-40 contains an immaterial footing error.
It appears the calculated value of the jurisdictional amount should be
$525,253 instead of $525,198.

SURREBUTTAL EXHIBIT MG 2.12

OKLAHOMA GAS & ELECTRIC COMPANY
ARVEC WORKPAPERS - COST OF CAPITAL
Pro Forma Test Year Ended June 30, 2017
Docket No. 16-052-U

Pro Forma Year of 6/30/2017

Line No	(2) Description	(3) Amont Beginning of Pro Forma Year (a)	(4) Pro Forma Adjustments	(5) Amount End of Pro Forma Year	(6) Proportion (Amount/Total)	(7) Rate % (b)	(8) Weighted Cost % (Col 6 x Col. 7		
1	Long Term Debt	$ 2,545,795,641	$ 337,473,946	$ 2,883,269,587	35.06%	5.47%	1.92%		1.92%
2	Common Equity	3,131,138,240	134,635,501	3,265,773,741	39.71%	10.25%	4.07%	1.6490380	6 71%
3	ADIT	2,096,229,421	(382,327,722)	1,713,901,699	20.84%	0.00%	0.00%		0.00%
4	Pre-1971 ADITC				0.00%		0.00%		0.00%
5	Post-1970 ADITC - Long Term Debt	1,113,202	(6,212)	1,106,990	0.01%	5.47%	0.00%		0.00%
6	Post-1970 ADITC - Short Term Debt	(8,660)	8,660		0.00%	0.76%	0.00%		0.00%
7	Post-1970 ADITC - Equity	1,369,790	(115,957)		0.02%	10.25%	0.00%		0.00%
8	Customer Deposits	77,925,617		77,925,617	0.96%	1.39%	0.01%		0.01%
9	Short-Term/Interim Debt	(19,888,203)	19,888,203		0.00%	0.76%	0.00%		0 00%
10	Current Accrued and Other Liabilities	643,516,325	(373,388,816)	270,127,509	3.28%	0.00%	0.00%		0 00%
11	Other Capital Items	9,633,870	87,577	9,721,446	0.12%	9.00%	0.01%		0.01%
12	Totals	$ 8,486,825,243	$ (263,744,819)	$ 8,223,080,424	100.00%	(A)	6.01%		$\boxed{8.652\%}$

Line No	(2) Description	(3) Amont Beginning of Pro Forma Year (a)	(4) Pro Forma Adjustments	(5) Amount End of Pro Forma Year	ARVEC Adjustments	(6) Proportion (Amount/Total)	(7) Rate % (b)	(8) Weighted Cost % (Col 6 x Col 7			
13	Long Term Debt	$ 2,545,795,641	$ 337,473,946	$ 2,883,269,587		35.06%	5.47%	1.92%		1 92%	
14	Common Equity	3,131,138,240	134,635,501	3,265,773,741		39.71%	**9.00%**	3.57%	1.6490380	5.89%	
15	ADIT	2,096,229,421	(382,327,722)	1,713,901,699		20.84%	0.00%	0.00%		0.00%	
16	Pre-1971 ADITC					0.00%		0.00%		0.00%	
17	Post-1970 ADITC - Long Term Debt	1,113,202	(6,212)	1,106,990		0.01%	5.47%	0.00%		0 00%	
18	Post-1970 ADITC - Short Term Debt	(8,660)	8,660			0 00%	0.76%	0.00%		0 00%	
19	Post-1970 ADITC - Equity	1,369,790	(115,957)	1,253,834		0.02%	10.25%	0.00%		0.00%	
20	Customer Deposits	77,925,617		77,925,617		0.96%	1.39%	0.01%		0.01%	
21	Short-Term/Interim Debt	(19,888,203)	19,888,203			0.00%	0.76%	0.00%		0.00%	
22	Current Accrued and Other Liabilities	643,516,325	(373,388,816)	270,127,509		3.28%	0.00%	0.00%		0 00%	
23	Other Capital Items	9,633,870	87,577	9,721,446		0.12%	9.00%	0.01%		0 01%	
24	Totals	$ 8,486,825,243	$ (263,744,819)	$ 8,223,080,424		100.00%	(A)	5.52%		7 84%	$\boxed{-0.814\%}$

Line No.	(2) Description	(3) Amont Beginning of Pro Forma Year (a)	(4) Pro Forma Adjustments	(5) Amount End of Pro Forma Year			(6) Proportion (Amount/Total)	(7) Rate % (b)	(8) Weighted Cost % (Col. 6 x Col 7				
25	Long Term Debt	$ 2,545,795,641	$ 337,473,946	$ 2,883,269,587	$ 314,232,944	$ 3,197,502,531	**38.88%**	5.47%	2.13%		2.13%		$ 3,197,502,531
26	Common Equity	3,131,138,240	134,635,501	3,265,773,741	$ (314,232,944)	2,951,540,797	**35.89%**	**9.00%**	3.23%	1.6490380	5.33%		2,951,540,797
27	ADIT	2,096,229,421	(382,327,722)	1,713,901,699		1,713,901,699	**20.84%**	0.00%	0.00%		0.00%		6,149,043,328
28	Pre-1971 ADITC						**0.00%**		0.00%		0.00%		
29	Post-1970 ADITC - Long Term Debt	1,113,202	(6,212)	1,106,990		1,106,990	**0.01%**	5.47%	0.00%		0 00%		
30	Post-1970 ADITC - Short Term Debt	(8,660)	8,660			0	**0.00%**	0.76%	0.00%		0.00%		
31	Post-1970 ADITC - Equity	1,369,790	(115,957)	1,253,834		1,253,834	**0.02%**	10.25%	0.00%		0 00%		
32	Customer Deposits	77,925,617		77,925,617		77,925,617	**0.95%**	1.39%	0.01%		0.01%		
33	Short-Term/Interim Debt	(19,888,203)	19,888,203			0	**0.00%**	0.76%	0.00%		0.00%		
34	Current Accrued and Other Liabilities	643,516,325	(373,388,816)	270,127,509		270,127,509	**3.28%**	0.00%	0.00%		0 00%		
35	Other Capital Items	9,633,870	87,577	9,721,446		9,721,446	**0.12%**	9.00%	0.01%		0 01%		
36	Totals	$ 8,486,825,243	$ (263,744,819)	$ 8,223,080,424		$ 8,223,080,423	100.00%	(A)	5.38%		7.48%	$\boxed{-0.358\%}$	