BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL TESTIMONY AND EXHIBITS OF

William Perea Marcus

on behalf of

THE OFFICE OF ARKANSAS ATTORNEY GENERAL LESLIE RUTLEDGE

March 30, 2017

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I. Introduction

Q. Have you previously presented direct testimony, Mr. Marcus?

A. Yes.

Q. What is the overall context of this rate case?

A. In its initial filing, Oklahoma Gas and Electric Company ("OG&E" or "the Company") requested a rate increase of $16.5 million. In rebuttal, it reduced its request slightly to $15.0 million. The Attorney General's investigation does not involve the detailed accounting audit provided by the General Staff but looks at a number of specific areas. Nevertheless, the AG's own analysis and its support for specific elements in the testimony of other parties has identified at least $13.3 million in reductions from OG&E's requested rate increase in areas including the capital structure and return on equity, incentive bonuses including stock-based compensation, vegetation management, administrative expenses, and the jurisdictional allocation.

I expect that the Staff's detailed audit as well as work by others such as the Arkansas Valley Electric Consumers will support additional rate reductions. To the extent that the Commission accepts recommendations of these parties reducing rate base or expenses, or increasing revenues, this would at least further reduce OG&E's requested base rate increase.

The detailed recommendations below summarize the impact of the AG's recommended adjustments. As noted above, it does not constitute a complete case on revenue requirement.

Q. What are your major recommendations?

A. My major recommendations are:

1. I recommend that OG&E's rate of return for ratemaking purposes be based on a hypothetical capital structure of 48% equity and 52% debt, consistent with the proxy group used by Staff.

2. I recommend inclusion of short-term and variable-rate debt held at the Holding Company level in OG&E's capital structure (Staff agrees on short-term debt), resulting in a reduction of 12 basis points in the rate of return.

3. I recommend a return on equity of 9.05% if the Formula Rate Plan is adopted.

4. I recommend a rate of return of 5.06% (7.09%, pre-tax), compared to OG&E's update of 6.01% (8.65% pre-tax) assuming that an FRP is adopted, as it has been for two other utilities. All of these changes to the return on rate base reduce OG&E's Arkansas revenue requirement by $8,271,000.

5. For short-term incentives, the Commission should use test year data, should remove excessive increases in STIP for corporate officers, and follow its precedent to share financial-based performance measures 50-50 with shareholders. This reduces OG&E's ratepayer expenses by $8,375,000 total company or $765,000 Arkansas jurisdictional.

6. The Commission should follow its past precedent and disallow all long-term stock-based incentives. OG&E's ratepayer expenses are reduced by $5,783,000 ($527,000 Arkansas jurisdictional).

7. The Commission should follow its past precedent and share the cost of D&O insurance equally with shareholders, reducing forecast ratepayer expenses by $552,000 total company ($50,000 Arkansas jurisdiction).

8. The Commission should normalize employee-related costs (severance, signing and retention bonuses, and relocation). The Company agreed to this change for severance and relocation. The Attorney General's outstanding adjustments for signing and retention bonuses reduce rates by $50,000 ($4,700 Arkansas).

9. The Commission should reduce advertising expenses and dues and donations in Accounts 909, 913, and 930 and remove a non-recurring inventory reduction in Account 910, reducing ratepayer expenses in these areas by $1,131,000 total company from its rebuttal case ($100,000 Arkansas jurisdiction).

10. The Commission should adopt ARVEC's adjustment to vegetation management ($879,000, all Arkansas jurisdictional) in this case, because the cost of moving to a shorter tree trimming cycle is increased by OG&E's deferred maintenance in 2013-14.

11. Based on ARVEC's testimony, the Commission should reduce the amount of money allowed to OG&E to compensate for costs no longer reimbursed by Enable Energy Services by at least 50% of the amount of the costs shifted from Enable to OG&E to encourage the utility to cut its costs when the size of the company is reduced. This amount is $2,321,502 (about $200,000 Arkansas jurisdictional).

12. Regarding depreciation expense, the Commission should adopt Staff's negative net salvage for Account 365, reducing depreciation expense by $746,000 ($53,000 Arkansas jurisdiction), because OG&E inappropriately excluded highway relocation payments from gross salvage.

13. The Commission should make three adjustments to working capital assets, reducing rate base by $2,847,000 ($236,000 Arkansas

jurisdiction). When my recommended return is applied, this adjustment reduces the rate increase by $17,000.

14. The Commission should not allow OG&E to recover 101.8% of its wind production plant and O&M revenue requirements between its two jurisdictions and should therefore remove an inconsistency in the jurisdictional allocation factor between Oklahoma and Arkansas. The result is to reduce Arkansas jurisdictional revenue requirements by $2,130,000 based on OG&E's rebuttal case.

15. The Commission should correct an error in the Supervised O&M allocation factor, which allocates administrative and general costs and general plant to jurisdictions and customer classes. This correction reduces the jurisdictional allocation to Arkansas by approximately $341,000 with OG&E's rebuttal case.

16. The Commission should include the Domestic Production Activities Deduction (DPAD) in the revenue conversion factor to reflect that the deduction will increase if proposed rates are higher than present rates. This reduces the rate increase by $32,715 per million dollars of income deficiency.

Because OG&E has not met its burden of proof that its proposed residential demand charge is cost-based and does not harm low-use customers while subsidizing larger users, I also recommend the rejection of this component of residential rate design, even as a voluntary rate.

II. Rate of Return

A. Capital Structure and Cost of Debt

Q. Will you comment on Mr. Hevert's rebuttal to you and to Staff on capital structure?

A. Mr. Hevert ignores long-standing precedent in Arkansas, when he claims that short-term debt should be excluded and the actual capital structure of the utility should be used.[1] The Commission uses a hypothetical capital structure to maintain congruence in financial risk between the utility and its proxy group, and that hypothetical capital structure typically includes short-term debt. The Commission order in Docket No. 15-011-U, which I cited in my direct testimony, states in part:

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U (at 44), the Commission holds that there should be congruence between the estimated cost of equity and the debt-to-equity ratio, whereby a lower debt-to-equity ratio decreases financial risk and decreases the cost of equity.[2]

Mr. Hevert is also ignoring the lack of balance between the capital structure of OG&E's regulated and unregulated activities that I pointed out in my direct testimony. Its unregulated activities (including its investment in the Enable Energy partnership) are financed with only 27.6% equity and with 76% short-term and variable-rate debt.[3] By contrast, OGE finances its regulated activities with much higher proportion (55.7%) of common equity – at a substantially higher cost to its ratepayers.

Q. After reviewing the Staff testimony, do you have any changes to your position on the Company's capital structure?

A. Yes. I will adopt Staff capital structure (52% debt and 48% equity with 2.9% short-term debt). The Staff proxy group has slightly less equity than Mr. Hevert's original proxy group (from which I estimated 51% debt and 49% equity with 2.79% short-term debt). I am still using the

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[1] Hypothetical capital structures have been used in all the energy utility Dockets in Arkansas where capital structure was litigated since 2005: Dockets 15-011-U, 13-028-U, 06-101-U, 04-176-U, and 04-121-U.

[2] Order No. 10 in Docket 15-011-U, p. 13.

[3] Direct Testimony of William P. Marcus for the Office of the Attorney General, p. 14.

cost rates in my direct testimony for debt, which includes variable-rate holding company debt in long-term debt and recognizes short-term interest rate increases in the pro forma period, two out of three of which have already occurred. I am updating other elements of the capital structure (deposits, accumulated deferred income taxes, and current and accrued liabilities) to Staff's latest estimates.

B. Return on Equity

1. OG&E's ROE "Validation" Methodology

Q. What is the issue here?

A. Mr. Hevert ignores the downward trend in ROEs both regionally and nationally, and his recommended ROE is inflated. There has been a downward trend since at least 2011[4] among the very utilities that Mr. Hevert selected for an Arkansas-adjacent comparison. 31 of 42 utilities (*i.e.*, almost three out of four) had ROE authorizations below 10.25% – OG&E's request in this case – and nine out of ten authorizations between 2014 and 2016 had ROEs below 10.25%.[5] And beyond the regional authorizations, I showed that two thirds of the national authorizations nationally since June 2014 were below 10%.[6]

Q. Has Mr. Hevert attempted to rehabilitate his case regarding authorized ROEs, nationally?

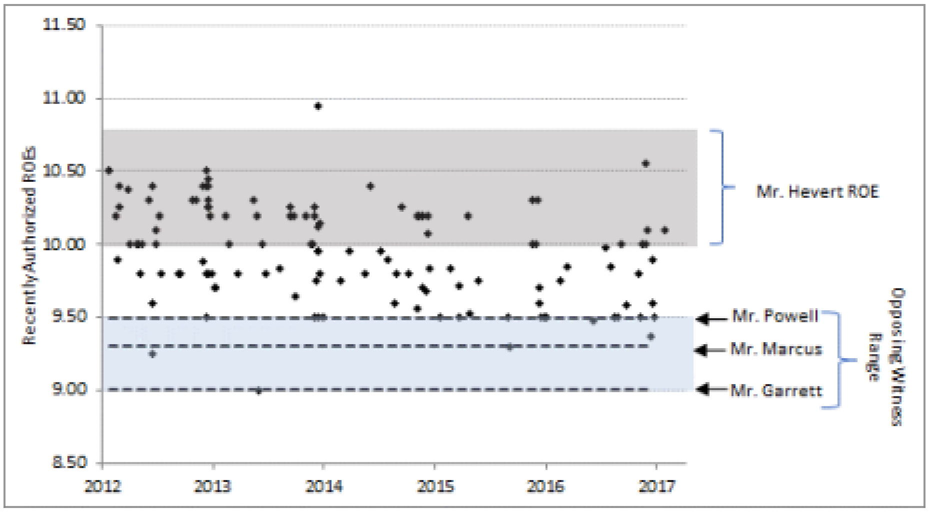
A. Yes, in rebuttal testimony, Mr. Hevert expands the period that he considers relevant for nation-wide ROE authorizations from one that starts in June 2014 to one that starts in January 2012, as shown in Chart 3 on p. 14 of his testimony. The witness provides no explanation or justification for such an expansion.

[4] Marcus Direct Testimony, p. 29.
[5] *Id.*
[6] *Id.*, p. 30.

For convenience, Mr. Hevert's Chart 3 is provided, here.

<u>Figure 1: Chart 3 from Hevert Rebuttal Testimony, p. 14</u>

Chart 3: ROE Witness Recommendations vs. Authorized Vertically Integrated Electric ROEs[17]



Mr. Hevert explicitly uses the chart to suggest that my recommended ROE is an outlier when compared to nation-wide ROEs. Such a characterization ignores evidence that regulators have been overly generous to utilities for years, allowing them to consistently equal or beat the Standard and Poors 500 index while delivering less risk to investors.[7] Given this context, it is not unusual that a fairly assessed ROE recommendation would be on the lower end of authorized ROEs.

Moreover, Mr. Hevert uses this chart to support his contention that I "suggest that the Cost of Equity has fallen to a level that supports [my] recommendation."[8] This is a highly inaccurate characterization of my testimony to suggest that it is authorized returns that are supporting my recommendation in this case. The Commission should disregard this point.

[7] Marcus Direct Testimony, pp. 45-50.

[8] Hevert Rebuttal Testimony, pp. 14 (starting at line 13) - 15.

But again, Mr. Hevert's reliance on authorized ROEs is inappropriate for the reasons I provide in my direct and the rest of this, rebuttal testimony.

Q. While you do not recommend relying on authorized ROEs in other jurisdictions, is there additional information that should be used to place Mr. Hevert's comments in perspective?

A. Yes. On March 20, 2017, the Oklahoma Corporation Commission adopted an authorized return on equity of 9.50% for Oklahoma Gas and Electric Company.[9] The Commission stated:

> Specifically, in this Cause, the Commission did not find Mr. Hevert's opinions persuasive. His recommended ROE of 10.25 percent was excessive in that each of his methods and the inputs he used appear to have been biased upward, resulting in a significantly inflated recommendation.[10]

This decision should carry substantially more weight than decisions in other jurisdictions as it involves the same utility with facts that are substantially similar to those in this proceeding.

2. Bias in Mr. Hevert's Presentation

Q. What is your response to Mr. Hevert's contention that his use of Mean High DCF results does not skew the perception regarding a reasonable cost-of-equity estimate?

A. Mr. Hevert claims that he has not explicitly or implicitly asked the Commission to ignore his Mean Low results.[11] This is incorrect.

While the Mean Low results nominally balance the Mean High results, the balance of Mr. Hevert's testimony implies (for reasons including Mr. Hevert's consideration of what he characterizes as an unusually

[9] Oklahoma Corporation Commission, Cause No. PUD 201500273, Final Order, March 20, 2017, pp. 4-5.

[10] *Id*. p. 5.

[11] Hevert Rebuttal, p. 46 (lines 10-11).

large capital program, including an environmental component, consideration of flotation costs and the state of the overall economy) that the Commission should ignore the Mean Low results and adopt estimates that are closer to the Mean High results.

However, when asked in the last CenterPoint Energy Arkansas general rate case to produce cases where he has recommended an ROE that is below his Mean DCF results, Mr. Hevert identified only one such case.[12] It was a non-representative case, however, of an unusual gas transmission and distribution company in Alaska,[13] where Mr. Hevert believed it reasonable to select gas transportation, or "pipeline," companies, of which nine of the 10 are limited partnerships,[14] to populate the proxy group and as a result ended up with DCF results whose means ranged from 13.85% to 14.76%,[15] while the witness recommended a point estimate of 13.75% for ENSTAR, the target company in the case. I note that 13.75% is more than 100 basis points above the highest of his Mean Low DCF results in that same case—12.72%. The only reason to use a lower number than he recommended

[12] In AG DR 4-4 from Docket No. 15-011-U, CURAD asked OG&E to identify each case where Mr. Hevert recommended an ROE point estimate that was below his Mean DCF results; the company was only able to produce one such case. Furthermore, when asked to provide instances where his "reasonable range" of ROEs included the means of his DCF results, the witness only provided one case (Tampa Electric Company's 2013 general rate case, Florida Public Service Commission Docket No. 130040-EU) in response (AG DR 4-5 from Docket No. 15-001-U).

[13] According to Mr. Hevert, "the Regulatory Commission of Alaska (RCA) has historically approved ROEs for ENSTAR that are a premium above ROEs for local gas distribution utilities in the United States. This is entirely appropriate for a number of reasons. Importantly, ENSTAR is not simply a local gas distribution company, but also a pipeline transmission company. This fact alone distinguishes ENSTAR from most natural gas distribution utilities. Additionally, ENSTAR faces specific risks and circumstances that, taken as a whole, create a unique risk profile that is unlike any other gas utility in the United States." Matter No. TA 262-4 before the Regulatory Commission of Alaska. Direct Testimony of Robert H. Hevert on behalf of ENSTAR Natural Gas Company and Alaska Pipelines Company, p. 6.

[14] *Id.*, p. 21 (Table 1).

[15] AG DR 4-4 from Docket No. 15-011-U. The Mean Low results in that case ranged from 11.94% - 12.72% and the Mean High results ranged from 16.05% - 17.11%.

was because the proxy group was unlike those typically used for local distribution companies in the "lower 48." So with that one exceptional case aside, Mr. Hevert has not produced any evidence that he ever recommended an ROE point estimate that was lower than his DCF results for normal, regulated gas distribution utilities.

In the end, contrary to Mr. Hevert's assertions in his rebuttal testimony, he presents average results which are bracketed by Mean High and Mean Low results, after the balance of his testimony discusses all of the reasons that the average results should be disregarded, and that a value above the mean, toward the Mean High results, should instead be used.

3. CAPM

a) Use of DCF-Derived Ex Ante *Market Risk Premium for use in CAPM*

Q. Mr. Hevert continues to try to justify his use of an "*ex ante*" CAPM, which he claims is a "conventional, reasonable and appropriate method of estimating the Company's Cost of Equity,"[16] by claiming that the cost of equity is a "forward-looking concept that focuses on investor expectations regarding future returns" and that "estimation of such returns, therefore, should be based on forward-looking data."[17] What is your response?

A. Analysts generally use historical average premiums or use premiums based on fundamental analysis such as those discussed in my direct testimony, regardless of whether the cost of equity is being estimated on an *ex ante* basis. In fact, Mr. Hevert used historical risk premiums as proxy for expected premiums before the financial crisis became full-

[16] Hevert Rebuttal Testimony, p. 48 (lines 8-10).

[17] *Id*., lines 7-8.

fledged. In November of 2008 the witness defended the practice using historical risk premiums, thus:

> Since the expected market risk premium is not directly observable, it is reasonable to use the historical average premium as an estimate or proxy for the expected risk premium. In that regard, the calculation of the risk premium should be based on the longest period possible to avoid giving undue consideration to unusual market conditions.[18]

Furthermore, this quote shows Mr. Hevert's understanding that the CAPM can provide forward-looking estimates even while he used risk premia derived from historical data. Therefore, it is clear that Mr. Hevert acknowledges the legitimacy of—indeed preference for—using historical premiums as proxy for CAPM's risk premium input. Thus, the witness contradicts his own testimony from past proceedings.

Q. Does Mr. Hevert provide reasoning for the switch from historical market risk premia ("MRPs"), which he acknowledges using in as late as 2008, to his DCF-based scheme?

A. Yes, he states:

> Under certain market conditions, the historical average MRP may be a reasonable estimate of investors' expected returns. One check on the reasonableness of using a historical MRP at any given time is to consider whether current Treasury yields are similar to the yields that were in place over the period used to calculate the historical MRP.[Footnote omitted] At the time of my analysis in the 2008 Otter Tail rate case, the 30-, 90-, and 180-day average 30-year Treasury yield ranged from 4.22 percent to 4.47 percent. Therefore, the use of an historical MRP was reasonable at that time. Current 30-year Treasury yields, however, are substantially below their long-term average, a direct result of Federal Reserve policies that were not in place in 2008. Consequently, historical averages may not adequately reflect investors' current expectations in the

[18] Hevert Direct Testimony in Docket No. G-008/GR 08 1075 before the Minnesota Public Utilities Commission, p. 34 (lines 8-12).

> current capital market and as such, it is necessary to consider forward-looking estimates of the MRP.[19]

Q. Are you persuaded by his explanation?

A. This explanation—that the switch was driven by "market conditions"—contradicts the explanation Mr. Hevert provided for using *ex post* estimates in the 2008 case. In the latter, Mr. Hevert expressed his belief that *ex ante* MRPs are not appropriate because they are not "directly observable," as quoted in my response to the second prior question, above. This has nothing to do with "market conditions."

If *ex ante* MRPs are not observable, why can they now be conjured from past DCFs? Moreover, not only has the witness's methodology and reasoning changed since 2008, but his recollection of why he preferred *ex post* MRPs in 2008 is incorrect. Mr. Hevert's directly stated belief in the 2008 case was that he believed in 2008 that *ex ante* MRPs were not directly observable, but he used historical MRPs in 2008 because market conditions were appropriate.

As I noted in my direct testimony, Mr. Hevert would have it both ways: the witness at once wants a large MRP (an input into the CAPM equation), which he achieves by observing low interest rates, but then applies the large MRP to future interest rates, whose forecast he says is higher than the very same interest rate that produce his MRP, when actually making the CAPM calculation.[20] This procedure is logically inconsistent.

Finally, Mr. Hevert's response to the effect of low interest rates on CAPM analysis is to introduce the past DCF results as way of backing into a CAPM result that his client will accept. What is interesting is

[19] Hevert Direct Testimony, pp. 49 (starting at line 5) – 50.

[20] Marcus Direct Testimony, p. 56.

that Mr. Hevert prefers to downplay his own DCF results—*i.e.,* the mean of the witness's DCF results ranges from 8.68%-9.03% but his final ROE recommendation is 10.25%—and yet Mr. Hevert uses DCF to prop up his CAPM analysis. If current DCF results are not sufficient why should the Commission expect past DCF results to be useful?

Q. What evidence does Mr. Hevert provide to contradict your showing that the witness's DCF-based, market-return estimate is unreasonable and unsustainable?

A. Very little. Mr. Hevert indicates that he disagrees with the academic and industry sources I produce in direct testimony showing that his estimates are unreasonable and unsustainable,[21] and indicates that his estimates are sustainable because the market-return implied by analysis is at the 49th percentile of market returns in the 87-year period, 1926-2015.

The witness's analysis lacks context and is therefore flawed because it provides no information about the risk-free rate during any of the 87 years he uses to develop the "total return" frequency table (Chart 6 of Hevert rebuttal). Therefore, the Commission is not provided the risk-free rate and MRP during those years.[22] The MRP for those years would be somewhere around 7.6% (using the arithmetic mean), which is well below the range he asserts is reasonable (*i.e.*, an implied MRP of between 10.68% and 11.35%).

Furthermore, the witness unreasonably uses returns from as far back as 1926. The percentile he presents includes returns during years after extreme market turbulence—such as the Great Depression and

[21] Hevert Rebuttal Testimony, pp. 54 (starting at line 15) – 55.
[22] Hevert Rebuttal Testimony, p. 43 (line 5).

World War II—which, as I showed in my direct testimony, is wholly inappropriate for the endeavor of estimating OG&E's cost of equity capital during the rate-effective period.

Finally, I illustrate very clearly that the current MRP is likely less than even the 7.6% supported by Ibbotson/Morningstar, much less Mr. Hevert's 10.68% and 11.35% levels. I will not repeat the testimony but refer the Commission to pages 51-64 of my direct testimony and the references and exhibits identified there.

The information in Chart 6 of Mr. Hevert's rebuttal testimony is entirely misleading and should be ignored.

Q. The witness contends that one of the third-party references I include in my direct testimony provides support for his use of the *ex ante* MRP derivation in for the CAPM.[23] What is your response?

A. Mr. Hevert cites Pablo Fernandez's discussion of the implied equity premium (IEP) in Fernandez's explanation of his survey results. This is the concept that Mr. Hevert calls the "implied market risk-premium" in his direct testimony.[24] The witness concludes that he "calculated the *ex ante* [implied] MRP in a similar manner" to the way Fernandez describes the calculation of the IEP it in his work. This is a logical leap and conclusion, however, that the Commission should ignore.

First, Fernandez's discussion of the IEP is in general terms only. The researcher notes that it is a concept that practitioners use, but that there are many methods of estimating it and 1) "there is not an IEP common for all investors" and 2) "there are many pairs of ([IEP, growth assumptions]) that accomplish the [Constant Growth DCF] equation"

[23] *Id.*, p. 59 (starting at line 6) -60.

[24] *See* Direct Exhibit RBH-3, pp. 1 and 8.

from Fernandez's paper that Mr. Hevert cites in his rebuttal testimony.[25]

Second, Fernandez makes no explicit or implicit endorsement of Mr. Hevert's *ex ante* MRP or the growth factor that it implies. Indeed, while Fernandez identifies and describes the notion of an implied equity premium, he notes the following, which undermines Mr. Hevert's reliance on the researcher's work:

> Many papers in the financial literature report different estimates of the IEP with great dispersion, as for example, Claus and Thomas (2001, IEP = 3%), Harris and Marston (2001, IEP = 7.14%) and Ritter and Warr (2002, **IEP = 12% in 1980** and -2% in 1999). There is no a common IEP for all investors.[26]

Crucially, to illustrate dispersion across IEP estimates, Fernandez cites Ritter and Warr as having an IEP of 12% in 1980, a year when the average 30-year bond yield was 11.27%;[27] Mr. Hevert's use of the Constant Growth DCF within the implied risk premium context for CAPM yields an "IEP" of 10.33% in a year when the 30-year bond yield was 2.84%.[28] Mr. Hevert's approach is clearly unreasonably exuberant and deserving of dismissal.

Finally, Mr. Hevert conflates Fernandez's discussion about the pure DCF method (for use within the context of an implied risk-premium concept) with Mr. Hevert's *ex ante* approach to the CAPM, which is a misdirection that the Commission should not ignore. Mr. Hevert's use of an "*ex ante* MRP" is a methodology the witness uses to top up his CAPM results; Fernandez, on the other hand, is speaking purely of

[25] P. Fernandez, J. Aguirreamalloa, and L. Corres, "Discount Rate (Risk-Free Rate and Market Risk Premium) used for 41 Countries in 2015: a survey," April 23, 2015, p. 13. IESE Business School – University of Navarra.
[26] *Id.*, pp13-14. Emphasis added.
[27] U.S. Federal Reserve. Available: www.federalreserve.gov/releases/h15/data.htm. Accessed May 16, 2016.
[28] *Id.*

using the Constant Growth DCF within the context of the DCF formulation, itself. It is in that context that Fernandez speaks of various choices of the growth rate that can lead to widely varying implied equity premia.

Q. Are there any empirical problems with the specific *ex ante* risk premiums that Mr. Hevert recommends?

A. Yes, there are two issues. First, his *ex ante* premiums, particularly from Value Line, are predicated on a "goldilocks" forecast of the future that is essentially an above average economy that is very positive for investors. Here is how Value Line describes its own forecast:

> The hypothesized 2020-2022 economic environment into which earnings are forecast is as follows: Unemployment will average just under 5% of the national labor force. There will be no major war in progress at that time. Industrial production will be expanding by 2.0% per year. Inflation will continue to be modest. Prices as measured by the broad- based GDP deflator will advance about 2% per year, on average. Long-term interest rates on AAA corporate bonds are projected to average 4.0% in the years 2020-2022. We expect the Federal Reserve to pursue moderately tighter monetary policies except in years in which the economy is slowing. Based on these assumptions, the Gross Domestic Product will average just over $23,300 billion in the years 2020-2022, a level that is nearly 26% above the estimated 2016 total of $18,567 billion.
>
> Things may turn out differently. But in the absence of knowledge of the future, we use the above assumptions, which appear to be most plausible. Thus we are able to apply a common economic environment to all stocks for the purpose of measuring relative growth potential.[29]

The key point here is that Value Line never claims that its stocks will grow at the rates that it projects. Rather, Value Line says that its goal is "measuring relative growth potential" using "a common economic

[29] Value Line, March 17, 2017, p. 900.

environment." I can see the reasonableness of this approach, which does not try to figure out which stocks might survive a recession better than others, in a stock picking exercise.

But Mr. Hevert misuses the statistics when he plugs them into an *ex ante* growth model and says that investors are "expecting" this nearly perfect economic future and would be disappointed if utilities were not given a rate of return that assuming that such a perfect economy will indeed occur.

Second, Mr. Hevert makes the first point more problematic by assuming that rosy forecast conditions in the next few years, such as those identified by Value Line, will persist forever.

Q. Has the Commission previously rejected the *ex ante* approach Mr. Hevert takes to calculating the risk premium for CAPM?

A. Yes. The Commission said the following about the practice in Docket No. 04-176-U, where Arkansas Western Gas ("AWG") witness, Dr. Roger Morin used the approach:[30]

> With regard to Dr. Morin's CAPM and [Empirical] CAPM analyses, *which are also variants of the RP methodology and subject to the same limitations*, the Commission finds that this analysis is based upon an excessive risk-free rate and excessive earnings growth assumptions which are unsupported and

[30] At p. 27 of his testimony, Dr. Morin states: "For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the aggregate market is currently 0.3% (VLIA 8/2004 edition), and the projected dividend and earnings growth for the more than 5000 stocks covered by Value Line is 10.0% and 16.4%, respectively. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market in the range of 10.3% to 16.7%, with a midpoint of 13.5%. Following the tenets of the DCF mode, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 13.7%. The implied risk premium is therefore 8.4% over long-term U.S. Treasury bonds that are currently yielding 5.3%. The same analysis applied to the S&P 500 index reveals a market risk premium of 8.8%. The average of the historical (7.2%) and prospective estimate (8.4%) is 7.8%.

> which produce excessive equity return results.[reference omitted] Current 30-year U.S. Treasury Bond yields are 4.36%, while the lower end of [Dr. Morin]'s proposed risk-free rate range is 4.5%.[reference omitted] [Dr. Morin]'s analysis also assumes earnings growth of 16.4%, but the record does not reflect an adequate response to questions raised about whether such high estimates are sustainable and the unreasonable results which can be extrapolated if they are adopted.[reference omitted][31]

As noted in this quote, Dr. Morin's CAPM and Empirical CAPM approaches suffer the same limitations as his Risk Premium approach, which are stated as:

> The Commission finds, first, that an appropriately produced DCF analysis provides a more accurate and independently determined required return on equity than does a RP analysis, which may be subject to fluctuating and unstable results as reflected by AWG's own analysis.[32]

Finally, the Commission found fault with the practice of using DCF results from non-utility market participants in a CAPM (or risk-premium) setting, as Mr. Hevert does:

> Additionally, the Commission notes the superiority of the DCF method, which uses only data from companies which have the same business and financial risks as the company subject to analysis, while [risk-premium] bases its analysis on market-wide data, incorporating into that analysis the risk profiles of companies "ranging from gold mining, to farming, to computer technology, to automobile manufacturing."[33]

Mr. Hevert's CAPM analysis—which the Commission considers to be a risk-premium method[34]—uses DCF results from companies ranging from Monsanto to Alcoa and from Ford Motor Company to Apple.[35]

[31] *Id.*, Order No. , p. 32.
[32] *Id.*, p. 31.
[33] *Id.*, p. 32.
[34] *Id.*
[35] Hevert Direct Ex. RBH-3.

4. Bond Yield plus Risk Premium

Q. What is the issue regarding Mr. Hevert's Bond Yield Plus Risk Premium analysis?

A. As I noted in my direct testimony, Mr. Hevert's analysis in the Bond Yield Plus Risk Premium—which in part includes a regression of a "risk premium" as calculated using authorized ROEs against time—is circular because it uses authorized ROEs. Mr. Hevert's rebuttal testimony adds nothing to the discussion that shows that the method is not circular, other than to suggest that Act 725 allows utilities to present authorized returns of other jurisdictions.[36]

First, having leave to make a case based on certain evidence does not mean that if one were to offer such evidence it would automatically be dispositive. OG&E has entered the regulated ROEs from other jurisdictions into the record for the Commission's consideration, but such information is no less circular just because Act 725 allows the Commission to consider it.

Second, Act 725 only allows that the Commission may consider evidence of approved returns from *recent* authorizations.[37] Mr. Hevert uses ROE-authorization data from as far back as 1980 to make his Bond Yield Plus Risk Premium analysis in this case. An ROE that was approved in 1980 has not "recently been approved." Thus, Act 725 does not support this Bond Yield Plus Risk Premium approach.

Q. Mr. Hevert states that academic research supports the inverse relationship between the risk premium and interest rates and that his Bond Yield Plus Risk Premium approach is consistent

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[36] Hevert Rebuttal, pp. 62 (starting at line 19) – 63.

[37] State of Arkansas, 90th General Assembly, Regular Session 2015, Act 725 (dated 03/27/15), Section (1) (c) (2).

with those findings as a way of contradicting the fact that the process is circular. What is your response?

A. Mr. Hevert states that the bond yield plus method is supported by academic research, and references citations he introduces in his direct testimony as support.[38]

The problem is that none of the academic pieces he cites use *regulatory, utility ROEs* to calculate *ex ante* returns,[39] and in fact use the DCF-determined returns along with contemporaneous bond rates to calculate what they typically call the *ex ante* risk premium.

The important point here is that while the papers Mr. Hevert references use DCF to calculate the risk premium and are therefore potentially not circular,[40] Mr. Hevert's approach to calculating the relationship is circular and highly suspect because it uses authorized returns.

Q. Mr. Hevert states that his Bond Yield Plus Risk Premium approach is a common approach to estimating the cost of

[38] Hevert Rebuttal Testimony, pp. 63 (starting at line 6) – 64.

[39] Each of the papers Mr. Hevert references in footnote 41 on p. 39 of his direct testimony uses the DCF—and decidedly not authorized returns—to calculate an implied risk premium Harris and Marston (1992), pp. 64-65; Brigham, Shome, and Vinson (1985), p. 37; Maddox, Pippert, and Sullivan (1995), p. 91). Furthermore, Mr. Hevert's citations are all from 1995 or before, use data from 1980 to no later than the early 1990s. The authors of the last publication (Maddox, Pippert, and Sullivan, 1995) are not even sure that they have found a reasonable relationship between risk premia and interest rates because the data are from periods, such as the early 1980s, when financial markets were the one that is The paper specifically states, "Yet, considering that our study covers a recent 14-year period, the hypothesis of a constant ex ante risk premium should also be tested over a longer period. It would also be interesting to test whether the long-term average of ex ante risk premiums converges with the long-term average of ex post risk premiums" (Maddox, Pippert, and Sullivan (1995, p. 95).

[40] There is still the potential that DCF forecasts that are based on analysts assumptions are circular insofar as those analysts maintain assumptions that regulators will not reduce return authorizations when interest rates fall because of regulatory inertia. In such cases, it is possible that DCF analysis for regulated utilities is at least somewhat circular by nature.

equity and is referenced in both academic and industry practitioner literature.[41] What is your response?

A. Mr. Hevert offers two references in support of this contention.

The first is the Chartered Financial Analyst (CFA) program. It is plausible that the CFA program does speak in some capacity regarding the Bond Yield Plus Risk Premium method, but we do not know precisely what the organization says about the practice (Mr. Hevert did not provide the reference as part of his workpapers). The material I could find indicates that the CFA program contemplates the Bond Yield Plus Risk Premium for individual companies, calculated with each particular company's debt yield; it says nothing about using government bond yields (rather than the company's own yields) and, importantly, utility authorized returns.[42] It is implausible that the organization accepts the use of or even contemplates the practice of using authorized returns as inputs into the Bond Yield Plus Risk Premium method.

The second reference is to Roger A. Morin's work called *New Regulatory Finance*. Dr. Morin has been a witness for utilities in many cost-of-capital proceedings across the country, including here in Arkansas.[43]

Dr. Morin's work should not necessarily be considered independent, and Mr. Hevert's citation to his work should be treated as a circularity in itself, given the similarity between Dr. Morin's and Mr. Hevert's

[41] Hevert Rebuttal Testimony, p. 61.
[42] CFA Institute, 2013. Chapter 3, Cost of Capital, p. 23. Available: tinyurl.com/hheytqr. Accessed, June 1, 2016.
[43] As noted above, Dr. Morin represented AWG in Docket No. 04-176-U. The Commission in that case rejected Dr. Morin's recommendation of 11% - his original recommendation was 11.5% - and instead adopted 9.7%. It cited Dr. Morin's "heavy reliance on the CAPM and [Risk Premium-method] results, which produce significantly higher returns than the DCF model," as one reason for the reduction. Docket No. 04-176-U, Order No. 6, p. 31.

client lists. In the past, the Commission has said, "The Commission also finds Dr. Morin's criticisms of the DCF method are exaggerated, if not flawed,"[44] and rejected his risk premium analysis because the results were "fluctuating and unstable."[45]

Moreover, Dr. Morin's work exhorts practitioners to use items that the Commission tends not to approve, such as flotation costs,[46] in order to prop up ROE requests. In fact, his "publication" is a roadmap to the various methods by which utility witnesses increase their ROE estimates.

Q. Has the Commission rejected the use of a supposed inverse relationship between equity risk premia and interest rates in the past?

A. Yes, in at least two instances, at least indirectly. Dr. Morin used the supposed inverse relationship between interest rates and risk premia in his authorized-ROE-based risk-premium analysis in Docket No. 04-176,[47] but the Commission roundly rejected his recommendations in that case, as just illustrated. Secondly, as noted, the Commission previously rejected the notion of raising ROE authorizations in the face of low interest rates in the 2013 Entergy Arkansas general rate case.

5. Third-Party Information

Q. Mr. Hevert attempts to impugn the forecasts of corporate and academic practitioners in several instances by noting that their estimates are lower than your recommended ROE of 9.30% for OG&E, a company that is less risky than the market,

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[44] *Id.*, p. 32.
[45] *Id.*, p. 31.
[46] Morin, Roger A., New Regulatory Finance, pp. 321-342. Public Utilities Reports, Inc. (2006), Vienna, Virginia. For a more detailed discussion of the flotation-cost issue, see Section IIB6 of this rebuttal.
[47] *See* Roger A. Morin's Direct Testimony (pp. 33-35) in that case.

which appears to the witness to be nonsensical.[48] Please respond.

A. The use of external estimates of the MRP is intended to provide the Commission context. Mr. Hevert concludes that because my estimate, which is for a company that is less risky than the market, is higher than those of corporate and academic participants then the corporate and academic participants must be wrong. That is high praise, indeed. However, it ignores the fact that I clearly state in my testimony that, while a lower ROE estimate would be reasonable, I originally recommended 9.30% for variety of reasons, which are summarized on pages 58-60 of my direct testimony.

Q. Can you point to an example?

A. Yes. While true that I have recommended an ROE that is higher than the country-wide CFO survey results reported in the Duke survey—from which Mr. Hevert concludes that the paper's results are not reasonable—the point regarding the survey results is that they represent important context that the Commission should use <u>in part</u> when deciding the reasonable ROE for OG&E.

In fact, I point out in my direct testimony that average risk premium from 2002 to 2016 was 3.61%.[49] Even with a conservatively high risk premium estimate of, say, 5% over the 10-year treasury and a 3% 10-year treasury rate (higher than the current 10-year Treasury bond rate of 2.46%[50]), an average market return of less than 8% is indicated. Again, this is context, a point that OG&E's witness continues, unreasonably, to ignore.

[48] Hevert Rebuttal Testimony, p. 54 lines 16-17).
[49] Marcus Direct Testimony, p. 43 (lines 12-13).
[50] 10-year Treasury Bond rate, average from February 10 to March 10, 2016, available at www.federalreserve.gov/datadownload/Choose.aspx?rel=H15.

Q. Mr. Hevert questions the relevancy of the Duke CFO survey that returned an average CFO cost-of-equity forecasts of 5.83% by invoking the notion of a hurdle rate.[51] Please respond.

A. Specifically, Mr. Hevert states:

> …the Duke CFO survey authors have noted a distinction between the expected market return on one hand, and the hurdle rate on the other. In prior surveys, the hurdle rate was significantly higher than the expected market return. For example, the authors' survey showed that the reported average hurdle rate, which is the return required for capital investments, was above 13.00 percent.[Footnote omitted] Mr. Marcus's reference to the 5.83 percent expected market return therefore should be given little weight.[52]

Hurdle rates for individual, prospective projects that particular companies contemplate undertaking (*i.e.*, not the cost of generally raising capital from prospective equity investors, but rather the return a company requires of a particular prospective operational or capital project before making the decision to move forward on that specific project) are not relevant to this proceeding and it is inappropriate and misleading for Mr. Hevert to have interjected them into this proceeding. In fact, the authors of the Duke CFO survey state very clearly,

> The [Weighted Average Cost of Capital] WACC should not be confused with the investment hurdle rate. The WACC is an analytical calculation that combines a model-based cost of equity (such as the CAPM) and the after-tax cost of debt (reflected in current borrowing rates). Given capital constraints, firms often impose a higher hurdle rate on *their* investments. For example, to allocate capital to an investment that promises a projected return exactly at the firm's WACC is equivalent to accepting a zero net present value project.[53]

[51] Hevert Rebuttal Testimony, p. 55 (lines 3-9).
[52] *Id.*
[53] Graham and Harvey, *The Equity Risk Premium in 2016*, p. 8; included in Direct Exhibit WM-3. Emphasis added to illustrate that the hurdle rate referenced in the paper refers to

And,

> While there is relatively little time-variation in the risk premium, premia are higher during recessions and higher during periods of uncertainty. We also link our analysis to the actual investment decisions of financial managers. We are able to impute the weighted average cost of capital given the CFO estimates of equity risk premia, current corporate bond yields and marginal tax rates. This imputed measure is significantly less than the WACCs that CFOs report using in project evaluation. One way to reconcile this is that CFOs use very long-term averages of equity premia and bond rates when calculating WACCs. We provide evidence on the actual hurdle rates used by companies. These hurdle rates are, on average, 400bp higher than the reported WACCs.[54]

In other words, when the authors indicate an average cost-of-equity survey they are talking about the long-term cost-of-equity in the equity market—which is the object of our endeavor in this proceeding—not the hurdle rate of particular, individual projects. Moreover, given that we are talking about cost-of-equity for a regulated utility that earns its return based on the amount of investment it has in rate base, it is nonsensical to talk about hurdle rates that may be different than costs of capital.

Q. Mr. Hevert notes that the author of the Welch survey report claims that the survey results should not be used in settings other than academic. What is your response?

A. I continue to believe that the Welch information provides useful context for the Commission as it considers the appropriate ROE for OG&E's regulated operations. I note that Mr. Hevert did not object to

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individual investments made by companies. For example, an energy master limited partnership might have a certain hurdle rate in mind as the deliberate about whether to build a large storage facility in a new location. Regulated utilities on the other hand, are provided a regulated return on all investments in their regulated rate base. This is the ROE that we are discussing in this proceeding and is based on the opportunity cost of investing other companies of similar risk, not in individual projects that other companies of unknown risk might contemplate.

[54] *Id*, p. 16.

the Fernandez survey, which, while including analysts and investment advisors in addition to academics, returned average total market returns of 7.9%.[55]

Q. Mr. Hevert claims that the Duff & Phelps material is not appropriate for use in utility rate-setting proceedings because the "Duff & Phelps MRP are so far removed from authorized returns."[56] What is your response?

A. As a preliminary matter, Mr. Hevert has not calculated the Duff & Phelps implied ROE correctly and thus the magnitude of the difference between authorized ROEs and Duff & Phelps ROEs is overstated and misleading. This is the third time since October 2015 that Mr. Hevert has misrepresented the Duff & Phelps material.

Duff & Phelps recommends using a normalized risk-free rate—currently, as it was last summer, the company recommends 4%—not current risk-free rates, as Mr. Hevert does in Table 13 of his rebuttal. For example, the current Duff & Phelps ROE for a company with a beta estimate of 0.67 (the beta Mr. Hevert uses in Table 13 of his rebuttal testimony) is 7.69%, not 6.21% as Mr. Hevert avers. In other words, Mr. Hevert's comparison between utility ROE authorization levels and Duff & Phelps ROEs is wrong because his calculation of the Duff & Phelps recommendation is also wrong.

Moreover, Mr. Hevert provided no rebuttal to my testimony on the free lunch that utility investors receive by obtaining returns equal to or above the S&P 500 for less risk.[57] Given the demonstrated, unrebutted free-lunch phenomenon for regulated utilities, there is no basis for the comparison that the witness makes between Duff & Phelps's

[55] Marcus Direct Testimony, p. 42.
[56] Hevert Rebuttal Testimony, p. 57 (2-4).
[57] Marcus Direct Testimony, pp. 45-48.

recommendation and authorized ROEs or the conclusion—that Duff & Phelps's MRP estimate is not appropriate.

Q. Does Mr. Hevert claim that Duff & Phelps suggests that "the CAPM formula can be adjusted to compensate for incremental risk with small size?"

A. Yes he does and quotes Duff & Phelps as suggesting a small-size premium of 3.58%.[58] Such a premium would result in a Duff & Phelps-calculated ROE of 11.23%,[59] which even Mr. Hevert agrees is too high.

In any case, it is clear from Duff & Phelps that the company does not endorse a size premium. The advisor states in its 2013 Client Alert:

> …consultants often add a premium for smaller firms based on the results in many research papers of a size premium. However, in our survey the average WACC for firms with less than $25 million in revenue is 10.6% and the WACC for the largest firms with annual revenue greater than $10 billion is 10.5%. …[T]here is no evidence of a size premium. The smallest firms reported (in 2012) a WACC of 9.3% and the largest firms 9.7%.[60]

In its 2015 Client Alert, Duff & Phelps does not even mention a size premium.

Whereas Duff & Phelps possibly indicates in its valuation handbook that CAPM might be adjusted for small size, it would appear unlikely that the company provides a full-throated endorsement, given the Duff & Phelps statement on the issue, provided above. In any case, Mr. Hevert has not provided any of the circumstances under which the

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[58] Hevert Rebuttal Testimony, p. 57 (lines 6-9).

[59] Size-adjusted CAPM = [RF + beta x MR] + Size Premium (SP) = [4.0% + 0.67 x 5.5%] + 3.58%. These values are taken from Duff & Phelps, except for beta, which, at 0.67, is the value Mr. Hevert uses.

[60] Duff & Phelps, March 20, 2013. "Client Alert: Duff & Phelps Decreases U.S. Equity Risk Premium Recommendation to 5.0%, Effective February 28, 2013"

advisor would approve of doing so or shown that Duff & Phelps would approve of doing so for the regulated operations of an electric utility.

Q. Mr. Hevert questions the validity of pension fund return forecasts. In particular, he references a Commission order from 2005 to bolster his argument against their consideration. How do you respond?

A. While true that the Commission spoke with disfavor on the use of pension fund forecasts in a 2005 case, it appears that it seriously considers the information I provide in other cases, which does include information from pension fund forecasters. For example, the Commission acknowledged my partial reliance on pension fund forecasts for context in Order No. 21[61] in Docket No. 13-028-U and my recommendation for an ROE authorization of 9.25%[62] in that case, while ultimately authorizing 9.30%.[63] This is one of the cases that I highlight in my direct testimony, a case that Mr. Hevert continues to ignore. In that case the Commission agreed with my position regarding an ROE witness who ignored the DCF-based evidence in front of him as a way of supporting his higher-than-reasonable ROE request.[64]

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[61] Docket No. 13-028-U, Order No. 21, p. 97.

[62] *Id.*

[63] *Id.*, p. 109.

[64] *Id.*, pp. 106-109. In particular, the Commission stated in response to the witness's reliance of "anomalous" interest rates as a reason to ignore DCF results:

> The Commission does not find EAI's and Staff's "anomaly" arguments persuasive. Similar arguments can be made for any time period in recent U.S. economic and financial history. It is unclear what exactly constitutes "normal" economic and financial conditions, and, in particular, what constitutes a normal level of interest rates. As shown …, the interest rates on U.S, 10-year Treasury bonds has varied between 1.80% and 13.93% since 1981. The country is currently in a low interest rate environment. In the past, including the early 1980s, this Commission allowed higher ROEs, which corresponded with extremely high interest rates during that period. It would be inconsistent to now adjust allowed ROEs upward because of currently low

I would add that it makes little sense to disregard pension fund forecasts in setting ROEs for regulated utilities simply because pension fund forecast are expected returns rather than required returns. Any investor that requires risk-appropriate returns that are higher than expected returns would not be an investor in that type of security. It makes no sense for pension fund managers to continue investing in stocks while *expecting* market returns of say 8.5%, but investors in utilities *require* returns of 10.25% when, as even Mr. Hevert agrees, utilities are less risky than the market.

6. Flotation Costs

Q. Has Mr. Hevert conceded his argument regarding flotation costs in the face of evidence that the Commission has not previously approved their recovery?

A. No. However, the witness has added no new support for his argument, which continues to contradict Commission policy on the matter. Mr. Hevert maintains that the calculations in Direct Exhibit RBH-8 "reasonably represent flotation costs for the Company,"[65] but declines to admit that those calculations on *past* flotation costs—seven of the 14 proxy-company stock issuances that the witness uses to calculate his flotation adjustment are from 2006 or earlier with one as far back as 2001. The fact that the witness's calculation is based on past flotation costs means that Mr. Hevert has failed to show "valid, sustainable,

interest rates. Further, the Fed has been pursuing those low interest rate policies for a number of years, a period which corresponds closely to the period of time new rates are effective for a typical utility. The allowed ROE should reflect current economic and financial conditions, not ignore those conditions. The DCF method reflects current economic and financial conditions through the price term in the DCF equation. … This Commission has always relied upon and afforded significant weight to the DCF method. Further the Commission notes the that 9.3% is the mid-point of Staffs recommended ROE range, without an upward adjustment for "anomalous" economic and financial conditions. *Id.*, pp. 108-109.

[65] Hevert Rebuttal Testimony, p. 69 (lines 4-6).

measurable, and material" prospective flotation costs, according to Commission precedent.[66]

In sum, the Commission should maintain its past policies regarding flotation costs and not include a flotation allowance in the return on equity based on the facts in this case.

7. Capital Market Environment

Q. Do you agree with Mr. Hevert indicates that interest rates are rising?

A. I won't repeat my direct testimony here, but simply state that the 30-year Treasury rate is now 3.06%,[67] which is slightly lower than it was in January when I filed my earlier testimony (3.11%[68]).

C. Recommended Rate of Return

Q. What is your recommended rate of return on common equity?

A. With consideration of the economic factors discussed above, I continue to believe that that a point estimate of 9.30% is reasonable if the Commission were to deny OG&E's application for the FRP. It is also still reasonable to reduce the regulated ROE to 9.05% if the Commission grants the FRP plan because of the significant reduction of risk and regulatory lag that it would provide my recommendation. Mr. Powell's testimony has a range of 8.9% to 10.1%, with a midpoint of 9.5%. My recommendation falls within Staff's DCF-based range, therefore, and as I noted in my direct testimony the information I have presented points directionally lower than the midpoint of Staff's range.

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[66] Docket No. 04-176-U, Order 6, p. 34.

[67] Federal Reserve. Available: http://tinyurl.com/z5fpjuv. Average 30-year Treasury rates, February 10-March 10.

[68] Marcus Direct Testimony, p. 21.

Q. Have you calculated the rate of return on rate base?

A. Yes. I use the Staff's capital structure, use my costs of short-term and long-term debt, which include variable-rate holding company debt as part of long-term debt and increase variable interest rates for the pro forma year, and use my recommended 9.05% return on common equity with FRP. The table below shows the calculation.

My recommendation is 95 basis points below OG&E's (156 basis points after tax gross-up). Of this amount 43 basis points (88 basis points after tax gross-up) results from my lower return on common equity, while the remainder results from changes to the capital structure and cost of debt. With the rate base in the Company's rebuttal case, the proposed rate base, the difference in revenue requirement is about $8,271,000.

Table 1: Recommended Rate of Return

OKLAHOMA GAS AND ELECTRIC COMPANY
ATTORNEY GENERAL'S SUMMARY OF COST OF CAPITAL PRO FORMA YEAR (INVESTOR OWNED UTILITIES)
SURREBUTTAL CASE
DOCKET NO. 16-052-U

(1) Line No.	(2) Description	(5) Amount End of Pro Forma Year	(6) Proportion (Amount/Total)	(7) Rate % (b)		(8) Weighted Cost % (Col.6 x Col.7)	(9) Pre-Tax Weighted Cost %
1	Long Term Debt	$ 2,793,106,553	34.92%	5.36%		1.87%	1.87%
2	Common Equity	2,770,518,356	34.64%	9.05%		3.13%	5.16%
3	Accumulated Deferred Income Taxes	1,876,827,334	23.46%	0.00%		0.00%	0.00%
4	Pre-1971 ADITC						
5	Post-1970 ADITC - Long Term Debt	1,172,737	0.01%	5.36%		0.00%	0.00%
6	Post-1970 ADITC - Short Term Debt	70,280	0.00%	1.51%		0.00%	0.00%
7	Post-1970 ADITC - Equity	1,163,253	0.01%	9.05%		0.00%	0.00%
8	Customer Deposits	77,441,663	0.97%	1.47%		0.01%	0.01%
9	Short Term/Interim Debt	167,385,484	2.09%	1.51%		0.03%	0.03%
10	Current, Accrued and Other Liabilities	302,724,921	3.78%	0.00%		0.00%	0.00%
11	Other Capital Items	8,082,810	0.10%	8.53%		0.01%	0.01%
12	Totals	$ 7,998,493,391	100.00%		(A)	5.06%	7.09%
				difference from OG&E		0.95%	1.56%
				OG&E rebuttal case Rate Base			529,153,916
				Revenue Requirement Difference			(8,271,118)

III. Expenses and Rate Base

A. Incentive Compensation

Q Will you summarize the position of OG&E's witness Ms. Ruden on incentive compensation?

A She argues that incentive compensation is "prudently incurred, known and measurable, reasonable, and necessary for the provision of utility service in Arkansas."[69] Overall, she claims that utilities such as OG&E have to manage a wave of aging employees by offering competitive salaries, including incentives.[70] She also claims that a financially healthy utility benefits customers.[71] She states

> If the Company does not perform well, the Company will not pay out incentives. If the Company does pay out incentives, this means that the Company has benefited customers with greater efficiency, lower costs, improved reliability, safety, compliance and healthier financial performance.[72]

Finally she claims that because other utilities offer incentives, particularly long-term incentives, ratepayers should pay for them.

Q. Will you comment on these issues?

A. Ms. Ruden's rebuttal discusses OG&E's challenges in attracting qualified candidates for jobs in OG&E. As she notes, retirements are increasing, and she claims OG&E is taking measures, including providing incentives, to attract and retain talent. At no point, in this discussion does Ms. Ruden refute our finding that team share target spending for non-executive/officer employees has increased much more slowly than incentives for executives and officers. In fact, from 2012 through 2015, non-exempt employees' Short-Term Incentive Program ("STIP") targeted payments <u>dropped</u> by 1.0% per

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[69] Rebuttal Testimony of Patricia Ruden for OG&E, p. 8.
[70] *Id.*, p. 7.
[71] *Id.*, pp. 8-9, 12-13.
[72] *Id.*, p. 11.

year. In the same period, officer STIP targeted payments increased by over 15%.[73] Given Ms. Ruden's rebuttal testimony, it appears that OG&E is spending to retain and attract executive and officer talent. Retaining and attracting talented non-executive/officer employees appears to have lower priority. System reliability, customer service and safety rely heavily on field employees and employees with customer contact, yet their target incentive levels have decreased or increased marginally over the last recorded four years.

When she argues that the Company will not pay out incentives if it does not perform well, Ms. Ruden ignores the position of its ratepayers. Ratepayers WILL pay out incentives if the Company does not perform well, based on test year ratemaking that assigns them with the cost of past levels of incentives. By confusing the company with its ratepayers, Ms. Ruden is actually making one of my points – that paying out 100% of financial based incentives assigns some of the Company's business risks to ratepayers:

> If employees earn their bonuses, shareholders are doing well and can afford to pay them. If they do not earn their bonuses, but 100% of the target level or test year bonuses are included in rates, the shareholders are cushioned and have their risk reduced because the money to pay the then non-existent bonuses is included in rates but is not paid out to employees. This means that the utility assumes no risk for the bonuses when ratepayers pay them and is partially sheltered from erosion of earnings if all financial incentives are included in rates.[74]

This problem is particularly true for Long-Term Incentive Plan ("LTIP") costs, where OG&E has recorded LTIP costs on its books and would charge them to ratepayers in this case, even though, when the actual performance

[73] Marcus Direct Testimony, p.68.

[74] *Id.*, p. 76.

was measured, no LTIP expenses were actually paid out to executives in 2015.[75]

While OG&E argues that ratepayers benefit from a financially healthy company, she still does not demonstrate that a significantly lower cost of capital results from OG&E's incentive program. My direct testimony addresses the issue and provides information from several sources in the literature that do not even support the nexus between high incentive payouts and corporate performance.[76] It also points out that corporate financial performance can be improved through productivity and efficiency but also through various forms of financial engineering, deferred maintenance, expensive infrastructure programs funded by ratepayers, or simply being good at securing rate increases for its investors.[77]

Finally, with respect to the argument that a utility cannot be competitive in the market unless ratepayers fund incentives based on financial considerations and the utility's stock price, Ms. Ruden ignores that many states do not allow full payout of financial incentives, particularly LTIP incentives based on stock, and utilities continue to offer those programs in any event, because they benefit shareholders.[78]

Q. Do OG&E's regulators have a practice of limiting incentive compensation payments?

A. Yes. The Oklahoma Commission overturned the recommendation of its Administrative Law Judge and disallowed 50% of short-term incentive compensation and 100% of long-term incentive compensation. "In this cause,

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[75] OGE Proxy Statement and Notice of Annual Meeting, May 19, 2016, p. 20, see Marcus Direct Testimony, p. 75.
[76] Marcus Direct Testimony, pp. 77-78.
[77] *Id.*, p. 78.
[78] *Id*. pp. 76-77. *See also* Direct Testimony of Mark Garrett for ARVEC, pp. 11-20.

the Commission is not persuaded that such [long-term incentive] compensation provided benefit to ratepayers."[79]

While OG&E's last three general rate cases have been settled in Arkansas, as noted in my direct testimony, the Arkansas Commission has not allowed LTIP for publicly traded companies[80] and has typically removed 50% of financially-based STIP payments, even changing settlement agreements to do so.[81]

Q. Do you still recommend reducing STIP payments and removing LTIP payments?

A. Yes.

Q. Since the filing of rebuttal testimony, have the amounts of short-term incentive program payments changed in a way that would affect your estimates?

A. Yes. My recommendations for STIP were based on allowing a 2015 payment without averaging (and then adjusting to remove 15% per annum increases in executive incentive compensation and for 50% of financial goals).

OG&E has since changed its recommendation to use an average of 2012-2016 instead of 2012-2015. This increases OG&E's recommendation for STIP from $14,143,068 to $14,828,724 including payroll taxes. Updated information has become available as to TY expensed STIP (excluding payroll tax) which is $9,559,259 ($10,263,820 with payroll tax). My recommended amount after disallowance based on this updated figure is $6,470,507, so that my recommendation reduces OG&E's request by $8,375,420 ($765,000 Arkansas jurisdictional).

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[79] Oklahoma Corporation Commission, Cause No. PUD 201500273, Final Order, March 20, 2017, pp. 6-7.
[80] Arkansas PSC Docket No. 15-015-U, Order No. 18, pp. 18-20. Order No. 21, pp. 4-5, 54-55.
[81] Arkansas PSC Docket No. 13-028-U, Order No. 21, pp. 4-5, 54-55. APSC Docket No. 15-011-U, Order No. 10, p. 22.

My alternate recommendation using OG&E's five-year average is $10,177,424 including payroll tax, as compared to OG&E's $14,828,724, for a reduction of $4,651,300 for financial goals.

Q. Has OG&E updated its estimate for the LTIP program?

A. OG&E has updated to a five-year average of 2012-2016, reducing its direct costs before payroll tax by $522,000 to $5,386,334.

Q. How does this update affect your recommendation?

A. Because I do not allow any long-term incentive compensation, I would thus reduce costs the full amount or $5,386,334 from OG&E's rebuttal position (total company) plus $396,972 in payroll taxes for a total of $5,783,307 (or $527,000 Arkansas). This reduction is $661,000 less than in my original testimony only because OG&E's request has been reduced.

B. Directors' and Officers' Liability Insurance.

Q. What is the issue regarding directors' and officers' liability (D&O) insurance?

A. Both the Attorney General and the General Staff[82] removed one-half of the cost of D&O insurance, reflecting the Commission's long-standing precedent that half of the costs of this insurance should be assigned to shareholders, because shareholders can receive payments from these policies if a company is sued.

Q. Did OG&E rebut this position?

A. No. The Company had no rebuttal, but it did not change its position in the schedules it included with its rebuttal filing.

Q. What is your conclusion?

[82] Direct Testimony of Troy Eggleton for APSC General Staff, p. 5.

A. As recommended by the Attorney General and the Staff, the Commission should follow its precedent and reduce insurance expenses by $552,000 total company. It should make a consequential adjustment to reduce working capital assets by $276,000 total company to remove half of the prepayment. The total is a reduction of about $50,000 Arkansas jurisdictional total revenue requirement.

C. Normalization of Expenses

1. Employment Expenses

Q. Will you discuss the normalization of employment expenses?

A. The Attorney General normalized four different types of employment expenses (severance, signing bonuses, relocation, and retention bonuses). For these four items, we used a 5-year average (after removing a retention bonus for one executive transferring from Enable to OG&E) and proposed a total reduction of $380,000 ($35,000 Arkansas).

The Staff also normalized severance and relocation for a total of $306,000.[83] OG&E updated the five year averages for these two items to 2016 and agreed to $275,000. Signing and retention bonuses were not mentioned in OG&E's rebuttal.

Q. What is your recommendation in light of the rebuttal testimony?

A. I accept the OG&E figure of $275,000 for severance and relocation.

The remaining outstanding costs to be normalized, where Staff made no adjustment and OG&E filed no rebuttal, are signing and retention bonuses. My recommendation to reduce rates by $49,839 for these two items[84] remains reasonable. The Commission should adopt it.

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[83] Prepared Testimony of Claude Robertson for APSC General Staff, p. 11.

[84] Prepared Testimony of William P. Marcus for the Attorney General, pp. 88-90.

2. Storm Damage

Q. Will you discuss the storm damage issue?

A. OG&E originally requested an increase of $693,354 (all Arkansas jurisdictional) for storm damage based on a three-year average (2013-15 plus the test year). The Staff endorsed a similar figure. The Attorney General recommended a five-year average without straight time labor, with a resulting adjustment of $409,592 (a reduction of $283,762 from OG&E's request). In rebuttal, OG&E agreed with the Attorney General's methodology, but updated the results to use 2012-2016. The resulting upward adjustment was $636,624.

Q. Do you accept OG&E's new estimate?

A. Yes, as it removes straight-time labor and uses a longer average than three years.

D. Vegetation Management

Q. What is the issue regarding vegetation management? (Adjustment C 2-29)

A. OG&E asks for $879,716 (all Arkansas jurisdictional) to move to a four-year tree-trimming cycle for vegetation management. While a request for increased spending was approved in Oklahoma,[85] OG&E previously had a four-year cycle in Oklahoma but did not spend authorized money and wound up off cycle there.[86] In Arkansas, OG&E claims never to have any kind of trim cycle at all but prioritizes work by reliability.[87]

Staff supports the increase to reach a four-year cycle.[88]

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[85] Oklahoma Corporation Commission, Cause No. PUD 201500273, Final Order, March 20, 2017, pp. 7-8.

[86] Report of the Administrative Law Judge on the Full Evidentiary Hearing, p. 49.

[87] Direct Testimony of Jarod Cassada for OG&E, p. 8.

[88] Eggleton Direct Testimony, pp. 9-11.

ARVEC opposes the increase and asks that the amount be held at the test year level.[89]

Q. Will you analyze the issue further?

A. In Arkansas, the Staff in Docket 10-067-U recommended $1,538,778 for vegetation management based on a three-year average,[90] which was higher than OG&E's test year spending but less than its original request. Staff's recommendation was carried through into the Settlement of that case.[91]

In Arkansas, spending in 2013-2014 was considerably below the levels approved in Docket 10-067-U.[92] This spending reduction increases the cost of moving toward a four-year cycle. Effectively, ARVEC is right that the cost of getting to a four-year cycle is higher in this case because of past deferred maintenance. The amount of Arkansas underspending in 2013-14 is likely to have even greater physical impacts than the dollar impacts given Mr. Rowlett's testimony regarding increasing numbers of line miles (at least in Oklahoma) and increasing contractor costs.[93]

This deferral of past maintenance causes me to agree with ARVEC that the test year amount (a significant increase over past spending) ought to be approved in base rates in this case, and the OG&E adjustment should be rejected.

Q. Do you dispute the reasonableness of a four-year trim cycle?

A. No. I do not dispute the reasonableness of a four-year cycle in this case, only the recouping of deferred maintenance from ratepayers in the process of moving toward that cycle. Costs of maintaining a four year cycle would be

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[89] Direct Testimony of Mark Garrett for ARVEC, pp. 40-42.
[90] Direct Testimony of Bill Dennis for APSC General Staff in Docket 10-067-U, page 8.
[91] Settlement Agreement in Docket 10-067-U, pp. 2-3.
[92] See Exhibit WM-SR-1, which contains spending levels from 2011-2015 and the Test Year from APSC DR 39.01 and AG DR 2.40.
[93] Rebuttal Testimony of Donald Rowlett for OG&E, p. 10.

automatically captured in the Formula Rate Plan, if adopted.[94] I believe that such an outcome would be reasonable – because it would address the Company's past deferral of maintenance in this case, while providing funding for an ultimate four-year trim cycle in the future.

E. Advertising, Dues, Donations, etc. (Accounts 907-915 and 930)

Q. Will you discuss advertising (IS-13)?

A. Staff agreed with OG&E in direct testimony except for the difference between the projected and actual test year,[95] and OG&E, in turn, agreed with Staff.

OG&E's rebuttal never mentioned the Attorney General's testimony, and therefore never defended the propriety of charging Arkansas ratepayers for (1) $92,000 of "safety" advertising including over $50,000 worth of ads telling Oklahoma drivers that texting while driving was illegal (no relation to provision of utility service) plus sponsorships of a rodeo and a botanical garden in Oklahoma City, (2) almost $15,000 of inappropriate expenses in Account 913, and (3) $7,300 to take employees to the Oklahoma City Dodgers (Acct. 930.1), (4) $29,000 of energy efficiency advertising that should not be booked to base rates, and (5) $19,000 of help wanted advertisements that were legitimate but booked to the wrong account (913, allocated over 95% to residential and small business customers instead of 921 – Administrative and General Non-Labor Expenses). Notwithstanding OG&E's attempt to marginalize the Attorney General's legitimate concerns, our position should be adopted.

Q. Will you discuss dues and donations (IS-33)?

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[94] On this point I agree with Staff witness Mr. Eggleton (at pages 10-11), though I disagree with him on the amount that should be approved in this rate case.

[95] Eggleton Testimony, p. 4.

A. The Staff made two adjustments that the Attorney General also made: to remove $12,830 Arkansas jurisdictional for Chamber of Commerce dues and $15,000 for a contribution to the foundation associated with the Edison Electric Institute (EEI).[96] OG&E accepted those adjustments in rebuttal testimony.

However, OG&E's rebuttal again never mentioned my testimony. OG&E never defended itself against our finding tens of thousands of dollars of sponsorships and event tickets, a golf tournament and similar items, all classified as "Info/Education/Safety." It never responded to our contention that OG&E failed to apply a standard adjustment to Holding Company costs for non-utility activities. It never mentioned that Arkansas ratepayers were being asked to pay for $70,500 in Oklahoma-only expenses. It never mentioned that $158,000 of what it called dues and donations were actually necessary expenses to keep production plants running efficiently that were booked in the wrong account. OG&E said nothing.

Q. Did OG&E rebut any of your testimony on Edison Electric Institute dues?

A. No. OG&E never explained how it met its burden of proof, given its failure in this case to answer a Staff question on EEI operations identical to a question it previously answered in Docket No. 10-067-U. And it never substantively put forth any information at all on EEI's operations.

Q. Do you still recommend disallowing 50 to 100% of EEI dues because of the lack of information provided by the Company?

A. Yes. My primary recommendation is to disallow all but $10,000 of mutual aid funding or $715,790, although I presented a minimum alternative that would disallow 50% of EEI's funding.

[96] Direct Testimony of Joy Brooks for APSC Staff, pp. 10-11.

Q. Did OG&E respond to your adjustment to Account 910 for a non-recurring write-off of in-home display inventory?

A. No.

Q. Do you still believe your reduction of $132,338 is warranted on a total company basis?

A. Yes. This is a non-recurring expense.

F. Expenses Transferred from Enable Energy

Q. What is the issue regarding expenses that were paid by Enable Energy in the test year but were adjusted to utility expenses in the rate case?

A. The Company is proposing to increase expenses by $4,643,005 (total company - $420,000 Arkansas) for costs it can no longer allocate to Enable Midstream Partners in the pro forma year.[97] ARVEC has challenged this increase.[98] In its rebuttal testimony of Mr. Forbes, OG&E argues that it cannot reduce corporate costs because the particular functions paid for by Enable are core functions necessary to the operation of the utility.[99]

Q. What is your position?

A. I support the general policy position of ARVEC on the grounds that long-run incremental costs of administration should come down (*e.g.*, executive salaries, etc.) if large pieces of the company are spun off. Reimbursing the Company for 100 cents on the dollar of shifted administrative costs gives it no incentive to cut administrative costs as it becomes smaller.

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[97] This figure is based on updated information based on the recorded test year. Rebuttal Testimony of Scott Forbes for OG&E, p. 2.

[98] Mark Garrett Testimony, pp. 49-51.

[99] Forbes Rebuttal Testimony, p. 3.

I note that the Commission could reasonably consider an alternative to the "all in" position of OG&E and the "all out" position of ARVEC. That alternative would reduce OG&E's Enable adjustment by half of the amount in the test year ($2,321,502 total company) or about $200,000 Arkansas jurisdictional) and that this reduction would continue through the FRP years unless Company can show that it has reduced costs to account for this reduction in the size of the company. Such an alternative would reflect that more costs may be fixed in the short term than in the longer term, when the Company can make more adjustments to administrative expenses over time.

G. Rate Case Expenses

Q. Is there an issue regarding rate case expense amortization at this time?

A. No. The Attorney General, Staff, and ARVEC all proposed a five-year amortization of rate case expenses in light of the Formula Rate Plan. OG&E agreed to that longer amortization in its rebuttal testimony.

H. Depreciation Expense

1. Accumulated Depreciation Differential Between Arkansas and Oklahoma

Q. Will you summarize the issue?

A. In adjustment C 2-40, OG&E proposes to increase Arkansas depreciation expense by $525,198 per year over ten years "to increase Arkansas accumulated depreciation to match with Company books."

Both the Attorney General and ARVEC opposed this adjustment. I noted that Arkansas adopted lower depreciation rates than Oklahoma in Docket No. 10-067-U, which should create a lower depreciation reserve, which was the intention of the APSC at the time. Mr. Mark Garrett for ARVEC suggested that changing the depreciation rates over a shorter period of time than the life of the assets could constitute retroactive ratemaking.

Staff's testimony significantly revised the numbers on which OG&E's adjustment was made and did not make any separate adjustment for this item.

Fundamentally, Staff used the Arkansas depreciation reserve figures to develop the remaining life associated with OG&E's plant. As a result, Staff's methodology has a different depreciation reserve than OG&E's and automatically recovers the difference in depreciation reserve between Arkansas and Oklahoma over the life of the plant. This is standard depreciation accounting, which is the right way to deal with this issue.

Q. Did OG&E agree with the Staff accounting for the difference in depreciable lives?

A. Yes, on page 9 of Mr. Rowlett's testimony. Therefore, the issue has been dealt with.

2. Other Depreciation Analysis

Q. Do you have any comments on the specific depreciation levels for specific accounts identified by Staff and ARVEC?

A. Yes. I have a comment on one single account based on my understanding of accounting principles related to depreciation.

I specifically agree with Staff's lower negative net salvage value for Account 365. The difference between OG&E and Staff is the treatment of reimbursements for highway relocations. These reimbursements are, as a matter of proper accounting, included in gross salvage, as OG&E admits below.

Mr. Spanos for OG&E chooses not to include these reimbursements when estimating future gross salvage and ends up with negative-50% net salvage. Staff does include them and ends up with net salvage of negative 47%.

APSC-88, which explains OG&E's position, states:

> The highway reimbursements have been removed from the analyses for Account 365 in Exhibit JJS-2, because they are not considered to occur throughout the life cycle of all vintages of overhead conductor. These amounts only affect gross salvage so there is no change to cost of removal or retirements. <u>It should be noted that these amounts are maintained in the book reserve.</u> [emphasis added][100]

Making a deliberate choice to remove a legitimate gross salvage item when forecasting negative net salvage, as Mr. Spanos has done, will cause ratepayers to pay too much to remove future wires in Account 365. Staff's adjustment to this account, which reduces the remaining life depreciation on this account from 2.65% to 2.54% (total company reduction of $746,559, Arkansas reduction of $52,581) is therefore warranted.

I. Working Capital Assets

1. Retail AFUDC for Transmission Project

Q. What is the issue regarding treatment of retail AFUDC on transmission projects?

A. Both Staff witness Mr. Taylor and I removed $7,531,483 for retail AFUDC on transmission projects. The rebuttal of company witness Mr. Forbes indicated that the projects were requested by the Southwest Power Pool and received CWIP treatment at FERC. He stated that retail AFUDC as a regulatory asset is the way in which this cost must be recovered.[101]

Q. What is your response?

A. I now agree with Mr. Forbes that the cost should not be removed. However, the information provided by Mr. Forbes, that this cost is amortized over the life of the specific transmission projects, causes me to recommend including a lower number in rate base than OG&E has included.

[100] OG&E Response to ASPC-88.

[101] Forbes Rebuttal Testimony, pp. 4-5.

Q. What is that lower number?

A. Because other elements of plant and accumulated depreciation are estimated at the end of the pro forma year, the adopted amount for this regulatory asset should not be a 13-month test year average ($7,531,483) but should also be the amount at the end of the pro forma year. That amount is known and measurable because of the fixed amortization and is $7,210,008 (the end of test year amount minus 12 months of amortization at $17,860 per month). My revised adjustment to OG&E's figure is a reduction to rate base of $321,475.

2. Miscellaneous Current and Accrued Assets (Account 174)

Q. Did OG&E rebut your adjustment to Account 174, Miscellaneous Current and Accrued Assets?

A. No, but OG&E did not change its estimate.

Q. Do you still believe that OG&E simply made a mistake for the months of April, May, and June 2016, as you stated in your direct testimony?

A. Yes. I also still believe that removing $2,250,315 from rate base is necessary to correct that mistake, particularly since OG&E never disputed my contention that this is just an error.

3. Prepaid Directors' and Officer's Liability Insurance

Q. Did OG&E rebut your adjustment for prepaid D&O insurance?

A. No, but OG&E did not change its estimate.

Q. Do you still believe that your adjustment of $275,948 total company is warranted?

A. Yes, it is appropriate, for the reasons stated in my discussion of the underlying D&O Insurance expense.

J. Revenue Conversion Factor (Domestic Production Activities Deduction or "DPAD")

Q. Did OG&E file any testimony regarding your reduction to the revenue conversion factor to include DPAD?

A. No.

Q. Do you continue to support your original adjustment shown in Table 22 of your direct testimony?

A. Yes, particularly since the Company has provided no evidence to indicate that my adjustment is incorrect or unreasonable.

K. Jurisdictional Allocation

1. Double Recovery of Wind Power Plant and O&M expenses

Q. What is the issue regarding wind power plant and O&M expenses?

A. OG&E has used different jurisdictional allocation methods in Arkansas (energy) and Oklahoma (average and excess 4 coincident peak demand), as pointed out by Dr. Blank for ARVEC.

Q. Why is this a problem?

A. By using an inconsistent jurisdictional allocation OG&E is over-recovering its wind power costs. It recovers 91.51% of those costs from Oklahoma by using AED/4CP but then recovers 10.29% of the costs from Arkansas by assigning costs to Arkansas using energy. The total allocation of wind power to the two states is 101.80%. Shareholders will be given the opportunity to earn more than their authorized rate of return with an allocation of 101.8% of wind power costs.

Q. Do you agree that the APSC previously allocated wind power to Arkansas using energy, as Mr. Smith testifies?

A. Yes. However, the material that Mr. Smith cites is not dispositive. Docket 10-067-U was a settlement, and settlements are not precedential. The OG&E Crossroads case, Docket 12-067-U, involved interim ratemaking between rate cases, but jurisdictional and class allocation factors are typically changed only in General Rate Cases. The case related to SWEPCO that Mr. Smith cites (Docket 13-033-U) involves purchased power and is therefore not on point.

Q. Will you analyze the issue further?

A. I believe that OG&E should not be allowed to collect more than 100% of its wind power costs from its two jurisdictions. The first key principle of jurisdictional allocation is that, if possible and reasonable, the allocation between the two jurisdictions should be the same so that all costs are recovered without giving the utility either a shortfall or (as in this case) a windfall. I do not make recommendations to change balanced jurisdictional allocation proposals by utilities that collect the revenue requirement, and will recommend changing the jurisdictional allocation only if there is a clear error or if accounting adjustments affecting only one jurisdiction create a lack of balance that must be remedied.

The second principle that class allocation should be the same as the jurisdictional allocation is less important than the first. Many utilities use different class and jurisdictional allocation methods. Southwestern Public Service, for example, uses 12CP for jurisdictional allocation between Texas and New Mexico and AE/4CP for class allocation in Texas.

In light of the characteristics of wind energy, which provides very limited and incidental amounts of capacity, a class allocation based on energy remains appropriate for Arkansas (and a system jurisdictional allocation based on energy for all jurisdictions could also have been appropriate).

Q. What do you recommend in this case?

A. I recommend that OG&E be allowed to collect only 100% of its total wind-related costs (for plant, O&M, etc.), by using the production demand allocation factor consistently for jurisdictional allocation in both states.

Because the characteristics of wind energy – in particular, its production of almost no reliable capacity, I would recommend recovering wind plant costs on a class basis using average demand, (energy) as the allocation factor.

Q. Have you estimated the impact of this change on the Arkansas revenue requirement?

A. Yes. My estimate based on OG&E's rebuttal case, is that my recommended change to wind power allocation would reduce the Arkansas jurisdictional revenue requirement by $2,130,000. The impact of this adjustment will change if rate of return, rate base, and other expenses change from OG&E's requested level.

2. Inclusion of Arkansas Regulatory Assets in Supervised O&M Factor

Q. What is the issue regarding the Supervised O&M Factor?

A. The Supervised O&M factor (including most O&M costs except fuel, purchased power, wheeling, and uncollectible accounts expenses) is used to allocate Administrative and General Expenses, general plant, and several smaller rate base items to jurisdictions and classes. I recommended removing the amortization of two Arkansas regulatory assets from the Supervised O&M factor. These regulatory assets do not require any administration or supervision. Moreover, corresponding Oklahoma regulatory assets related to advanced metering were not included in that factor, so it is unbalanced between the two states. The inclusion of these regulatory asset amortization items appears to me to be simply an error that needs to be corrected.

Q. Did OG&E provide any rebuttal to you on this issue?

A. No. Mr. Smith for OG&E commented on a number of other jurisdictional allocation issues raised by Staff and ARVEC, but he ignored this one.

Q. Does your position change?

A. No. The Company did not defend itself on this issue, because there really is not any good defense. But the fact that there is no rebuttal should mean that the correction that I recommend should be adopted, not the Company's undefended and erroneous position.

Q. Has your estimate of the numerical amount of this adjustment changed?

A. Yes. I originally calculated a reduction of $312,000 to the Arkansas jurisdictional revenue requirement based on OG&E's direct case. Updating to OG&E's rebuttal case and applying my recommended change to the allocation of wind production plant before making this adjustment, the correction to Supervised O&M is estimated to reduce the Arkansas jurisdictional revenue requirement by $341,000. The impact of this adjustment will be reduced by reductions to expenses, rate base, and rate of return from OG&E's rebuttal case proposed by intervenors and Staff.

3. Allocation of Accounts Receivable

Q. What is the issue regarding the allocation of accounts receivable?

A. I proposed to allocate accounts receivable by the total of all rate revenues, not just base rate revenues. Accounts receivable arise from riders for fuel adjustment, energy efficiency, and other purposes, as well as from base rates.

Q. Did OG&E provide any rebuttal to you on this issue?

A. No. As with supervised O&M, Mr. Smith also said nothing about this issue.

Q. Does your position change?

A. No. The unrebutted facts are clear that the allocation factor used by OG&E is incorrect for both jurisdictional and class allocation (because rider revenue is part of accounts receivable). The Commission should change it.

Q. Have you provided more detail regarding the impacts of your three recommended adjustments to the jurisdictional allocation?

A. Yes. They are provided in Exhibit WM-SR-2.

IV. Residential Demand Charges

Q. What are the positions of other parties related to residential demand charges following Staff direct testimony and OG&E rebuttal testimony?

A. Staff proposed that the default demand charge be rejected. Instead, Staff proposed that instead a voluntary program be put in place where customers who sign up for a rate with a demand charge would receive bill protection and would receive the best bill compared to the TOU rate.[102] OG&E reluctantly agreed to Staff's proposal, [103] while continuing to claim that residential demand charges will increase the accuracy of pricing.

Q. Has the Oklahoma Commission <u>now</u> rejected mandatory residential demand charges, while only the ALJ had rejected them at the time when you filed your direct testimony?

A. Yes. In the final order, the Commission affirmed the findings of the ALJ rejecting residential demand charges, while changing some wording.[104]

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[102] Direct Testimony of Robert Swaim for Staff, p. 20.
[103] Rebuttal Testimony of Bryan J. Scott for OG&E, p. 5.
[104] Oklahoma Corporation Commission, Cause No. PUD 201500273, Final Order, March 20, 2017, pp. 12-14.

Q. Is Mr. Scott right when he says that demand charges increase the accuracy of pricing for residential customers.

A. We don't know, because Mr. Scott is accepting as an article of faith an hypothesis that should be tested and proven. He states:

> The demand charge properly assigns costs to customers, including to those who have higher demands with corresponding lower usage. This ratio of energy to demand is known as load factor. Lower load factor customers impose higher costs on the utility; a demand rate properly assesses higher bills to these customers relative to customers with the same kWh usage but with a lower demand. These customers with the same kWh, but a lower demand impose fewer costs upon the system.[105]

In this statement, Mr. Scott is conflating a customer's individual maximum demand with system demand (the class or system peaks used to allocate distribution, transmission, and generation costs). The issue for the residential class is that my direct testimony has provided information that, for some utilities, Mr. Scott's statement is not true. For these utilities, smaller residential customers often have lower load factors measured against their own maximum demand than larger customers, even though they have equal or better load factors than large customers measured against measures of class, system, or equipment peak demand. The coincidence of maximum demand with other measures of demand is lower for smaller customers. In such cases, a residential demand charge is not cost-based.

Whether this finding is also true for OG&E is a matter for investigation – even though OG&E never systematically collected its own data to enable this investigation to take place. The idea that lower load factor (based on a customer's own demand) equals lower cost for residential customers should not simply be accepted as truth but must be tested.

Q. Has the Oklahoma Commission required OG&E to collect data similar to that which you requested and that OG&E could not

[105] Scott Rebuttal Testimony, p. 7.

provide in this case before presenting any new residential demand charge?

A. Yes. The provisions of the Oklahoma order require that OG&E conduct a better analysis of the cost basis of demand charges. The language of the order in this regard was actually clarifying language requested by OG&E.

> Before proposing the introduction of any new demand charges, OG&E will be required to provide a cost of service study of small, medium, and large users within major rate classes not currently containing a demand charge.[106]

This requirement is very similar to the analysis that I was trying to pursue in this case.

Q. What is your position on the voluntary rate?

A. I recommend that the voluntary residential demand charge be rejected, because OG&E has not done its necessary homework and thus has not borne its burden of proof to show that residential demand charges – whether voluntary or not – are not systematically biased against small customers, while potentially subsidizing larger users who could benefit from the voluntary rate.

While OG&E and Staff have effectively agreed to give ratepayers a voluntary option with a free trial period (best bill provision), I still do not believe that such an approach is advisable, even for a voluntary rate.

There are two problems. First, I do not believe it reasonable to put in place even a voluntary rate that is likely to subsidize large users. Of course, customers who benefit from a demand charge would react positively to the rate, but if the rate is not cost-based, a number of them may be gaining because they are subsidized.

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[106] *Id.*, p. 12.

Second, the experience gained from customer acceptance of a voluntary rate cannot be extrapolated to provide any information on the acceptability or the cost basis of a mandatory rate in the future, particularly if there are winners and losers from the rate on a default basis, and only the winners are signing up for the voluntary rate.[107]

Q. Does this conclude your testimony, Mr. Marcus?

A. Yes, it does.

[107]Mr. Scott points to optional rates for Arizona Public Service as showing the reasonableness of demand charges. (Scott Rebuttal Testimony, p. 6) These optional rates again largely benefit structural winners.

Exhibit WM-SR-1 Vegetation Management Spending, 2011 to Present

Arkansas Distribution Vegetation Management Spending 2011-Test Year

	2011	2012	2013	2014	2015	Test Year
Arkansas Dist Line Cycle	1,328,916	1,492,719	1,027,196	855,193	1,023,410	1,262,201
Arkansas Dist Line Non Cycle	83,477	77,587	80,317	291,369	449,833	552,995
Arkansas Distribution Substation	52,288	52,480	54,172	52,474	55,550	99,473
Total Arkansas Distribution	**1,464,681**	**1,622,786**	**1,161,685**	**1,199,036**	**1,528,793**	**1,914,669**

Source: 2011-2015 from APSC DR 39.01, Test Year from AG DR 2.40

Exhibit WM-SR-2 Impacts of Changes to Jurisdictional Allocation

OKLAHOMA GAS & ELECTRIC COMPANY
TEST YEAR ENDING JUNE 30, 2016
DOCKET NO. 16-052-U
Schedule G-1 Jurisdictional Only

		OG&E Rebuttal Case As Filed			OG&E Rebuttal Case - AG Change to Wind Jurisdiction			
		1	2	3	1	2	3	
LN NO.	DESCRIPTION	TOTAL COMPANY PRO FORMA	TOTAL ARK. RETAIL JURISDICTION	TOTAL JURISDICTIONS NOT AT ISSUE	TOTAL COMPANY PRO FORMA	TOTAL ARK. RETAIL JURISDICTION	TOTAL JURISDICTIONS NOT AT ISSUE	WIND ONLY ARK. RETAIL DIFFERENCE
	RATE BASE (a)							
1	GROSS PLANT IN SERVICE	$9,853,391,057	$785,289,328	$9,068,101,729	$9,853,391,057	$768,547,444	$9,084,843,613	($16,741,884)
2	ACCUMULATED DEPRECIATION	$3,890,191,599	$309,932,163	$3,580,259,436	$3,890,191,599	$305,992,039	$3,584,199,560	($3,940,125)
3	TOTAL NET PLANT (L1-L2)	$5,963,199,458	$475,357,165	$5,487,842,293	$5,963,199,458	$462,555,405	$5,500,644,052	($12,801,759)
4	WORKING CAPITAL ASSETS	$440,490,777	$44,622,766	$395,868,011	$440,490,777	$44,504,546	$395,986,231	($118,220)
5	OTHER RATE BASE ITEMS	$110,097,088	$9,173,985	$100,923,103	$110,097,088	$9,173,985	$100,923,103	$0
6	TOTAL RATE BASE (L3+L4+L5) (A)	$6,513,787,323	$529,153,916	$5,984,633,407	$6,513,787,323	$516,233,936	$5,997,553,386	($12,919,979)
	NON-FUEL OPERATING REVENUES							
7	PRESENT RATE SCHEDULE/CLASS REVENUES (b)	$1,140,853,507	$94,621,808	$1,046,231,699	$1,140,853,507	$94,621,808	$1,046,231,699	$0
8	OTHER OPERATING REVENUES	$18,514,395	$694,920	$17,819,475	$18,514,395	$694,920	$17,819,475	$0
9	TOTAL OPERATING REVENUES (L7+L8) (A)	$1,159,367,902	$95,316,728	$1,064,051,174	$1,159,367,902	$95,316,728	$1,064,051,174	$0
	EXPENSES (c)							
10	OPERATION AND MAINTENANCE EXPENSE							
11	PRODUCTION	$135,955,259	$14,513,571	$121,441,688	$135,955,259	$14,334,229	$121,621,030	($179,341)
12	TRANSMISSION & REGIONAL MARKET	$20,674,991	$1,387,645	$19,287,346	$20,674,991	$1,387,645	$19,287,346	$0
13	DISTRIBUTION	$79,931,067	$8,510,031	$71,421,036	$79,931,067	$8,510,031	$71,421,036	$0
14	CUSTOMER ACCOUNTS	$20,188,367	$1,924,905	$18,263,462	$20,188,367	$1,924,905	$18,263,462	$0
15	CUSTOMER SERVICES AND INFORMATION	$8,843,264	$794,297	$8,048,967	$8,843,264	$794,297	$8,048,967	$0
16	SALES	$3,883,575	$354,307	$3,529,268	$3,883,575	$354,307	$3,529,268	$0
17	ADMINISTRATIVE AND GENERAL	$132,558,237	$13,066,673	$119,491,564	$132,558,237	$12,969,214	$119,589,023	($97,458)
18	TOTAL OPERATION AND MAINTENANCE EXPENSE (Sum L11 thru L17)	$402,034,760	$40,551,429	$361,483,331	$402,034,760	$40,274,629	$361,760,131	($276,800)
19	DEPRECIATION & AMORTIZATION EXPENSE	$308,667,370	$24,082,435	$284,584,935	$308,667,370	$23,400,503	$285,266,867	($681,933)
20	TAXES OTHER THAN INCOME TAXES	$81,391,362	$6,834,046	$74,557,316	$81,391,362	$6,605,490	$74,785,872	($228,556)
21	FEDERAL & STATE INCOME TAXES	$56,245,250	$1,160,251	$55,085,000	$56,245,250	$1,832,432	$54,412,818	$672,182
22	TOTAL EXPENSES (Sum L18 thru L21) (A)	$848,338,742	$72,628,161	$775,710,581	$848,338,742	$72,113,054	$776,225,688	($515,107)
23	OPERATING INCOME (L9-L22)	$311,029,160	$22,688,567	$288,340,593	$311,029,160	$23,203,674	$287,825,486	$515,107
24	EARNED RETURN ON RATE BASE (L23 / L6)		4.2877%	4.8180%		4.4948%	4.7990%	4.4948%
	COST OF SERVICE REVENUE REQUIREMENT							
25	REQUIRED RETURN ON RATE BASE (EQUAL RATES OF RETURN)	6.010%	6.010%	6.010%	6.010%	6.010%	6.010%	6.010%
26	REQUIRED OPERATING INCOME (L6*L25)	$391,478,618	$31,802,150	$359,676,468	$391,478,618	$31,025,660	$360,452,959	($776,491)
27	INCOME DEFICIENCY / (SURPLUS) (L26-L23)	$80,449,459	$9,113,583	$71,335,875	$80,449,459	$7,821,986	$72,627,473	($1,291,598)
28	REVENUE CONVERSION FACTOR (d) (A)	1.649038	1.649038	1.649038	1.649038	1.649038	1.649038	0.000000
29	REVENUE DEFICIENCY / (SURPLUS) (L27*L28)	$132,664,214	$15,028,645	$117,635,569	$132,664,214	$12,898,752	$119,765,463	($2,129,894)
30	RATE SCHEDULE REVENUE REQUIREMENT (L7+L29)	$1,273,517,721	$109,650,453	$1,163,867,268	$1,273,517,721	$107,520,560	$1,165,997,162	($2,129,894)
31	FUEL REVENUES @ PRESENT RATES (b)		$64,922,446			$64,922,446		$0
32	OTHER RIDERS @ PRESENT RATES (b)		$10,455,485			$10,455,485		$0
33	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L29 / L7)		15.88%			13.63%		-2.25%
34	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L29 / (L7+L31))		9.42%			8.08%		-1.33%
35	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L29 / (L7+L31+L32))		8.84%			7.59%		-1.25%
36	TOTAL REVENUE REQUIREMENT (b) (L8+L30+L31+L32)		$185,723,304			$183,593,411		($2,129,894)

OKLAHOMA GAS & ELECTRIC COMPANY
TEST YEAR ENDING JUNE 30, 2016
DOCKET NO. 16-052-U
Schedule G-1 Jurisdictional Only

LN NO.	DESCRIPTION	OG&E Rebuttal Case - AG Wind & SUP_OM Jurisdiction				OG&E Rebuttal Case - AG Wind & SUP_OM & Accts. Receivable Jurisdiction			
		1 TOTAL COMPANY PRO FORMA	2 TOTAL ARK. RETAIL JURISDICTION	3 TOTAL JURISDICTIONS NOT AT ISSUE	SUP_OM ONLY ARK. RETAIL DIFFERENCE	1 TOTAL COMPANY PRO FORMA	2 TOTAL ARK. RETAIL JURISDICTION	3 TOTAL JURISDICTIONS NOT AT ISSUE	Accts Receivable ARK. RETAIL DIFFERENCE
	RATE BASE (a)								
1	GROSS PLANT IN SERVICE	$9,853,391,057	$767,401,285	$9,085,989,772	($1,146,159)	$9,853,391,057	$767,401,285	$9,085,989,772	$0
2	ACCUMULATED DEPRECIATION	$3,890,191,599	$305,445,387	$3,584,746,212	($546,652)	$3,890,191,599	$305,445,387	$3,584,746,212	$0
3	TOTAL NET PLANT (L1-L2)	$5,963,199,458	$461,955,898	$5,501,243,560	($599,507)	$5,963,199,458	$461,955,898	$5,501,243,560	$0
4	WORKING CAPITAL ASSETS	$440,490,777	$44,496,441	$395,994,336	($8,105)	$439,867,155	$43,872,818	$395,994,336	($623,622)
5	OTHER RATE BASE ITEMS	$110,097,088	$9,173,985	$100,923,103	$0	$110,097,088	$9,173,985	$100,923,103	$0
6	TOTAL RATE BASE (L3+L4+L5) (A)	$6,513,787,323	$515,626,324	$5,998,160,999	($607,613)	$6,513,163,700	$515,002,701	$5,998,160,999	($623,622)
	NON-FUEL OPERATING REVENUES								
7	PRESENT RATE SCHEDULE/CLASS REVENUES (b)	$1,140,853,507	$94,621,808	$1,046,231,699	$0	$1,140,853,507	$94,621,808	$1,046,231,699	$0
8	OTHER OPERATING REVENUES	$18,514,395	$694,920	$17,819,475	$0	$18,514,395	$694,920	$17,819,475	$0
9	TOTAL OPERATING REVENUES (L7+L8) (A)	$1,159,367,902	$95,316,728	$1,064,051,174	$0	$1,159,367,902	$95,316,728	$1,064,051,174	$0
	EXPENSES (c)								
10	OPERATION AND MAINTENANCE EXPENSE								
11	PRODUCTION	$135,955,259	$14,334,229	$121,621,030	$0	$135,955,259	$14,334,229	$121,621,030	$0
12	TRANSMISSION & REGIONAL MARKET	$20,674,991	$1,387,645	$19,287,346	$0	$20,674,991	$1,387,645	$19,287,346	$0
13	DISTRIBUTION	$79,931,067	$8,510,031	$71,421,036	$0	$79,931,067	$8,510,031	$71,421,036	$0
14	CUSTOMER ACCOUNTS	$20,188,367	$1,924,905	$18,263,462	$0	$20,188,367	$1,924,905	$18,263,462	$0
15	CUSTOMER SERVICES AND INFORMATION	$8,843,264	$794,297	$8,048,967	$0	$8,843,264	$794,297	$8,048,967	$0
16	SALES	$3,883,575	$354,307	$3,529,268	$0	$3,883,575	$354,307	$3,529,268	$0
17	ADMINISTRATIVE AND GENERAL	$132,558,237	$12,721,308	$119,836,929	($247,906)	$132,558,237	$12,721,308	$119,836,929	$0
18	TOTAL OPERATION AND MAINTENANCE EXPENSE (Sum L11 thru L17)	$402,034,760	$40,026,723	$362,008,037	($247,906)	$402,034,760	$40,026,723	$362,008,037	$0
19	DEPRECIATION & AMORTIZATION EXPENSE	$308,667,370	$23,361,157	$285,306,213	($39,345)	$308,667,370	$23,361,157	$285,306,213	$0
20	TAXES OTHER THAN INCOME TAXES	$81,391,362	$6,574,388	$74,816,974	($31,101)	$81,391,362	$6,574,388	$74,816,974	$0
21	FEDERAL & STATE INCOME TAXES	$56,245,250	$1,980,787	$54,264,464	$148,354	$56,245,250	$1,987,196	$54,258,054	$6,409
22	TOTAL EXPENSES (Sum L18 thru L21) (A)	$848,338,742	$71,943,056	$776,395,687	($169,998)	$848,338,742	$71,949,465	$776,389,277	$6,409
23	OPERATING INCOME (L9-L22)	$311,029,160	$23,373,672	$287,655,487	$169,998	$311,029,160	$23,367,263	$287,661,897	($6,409)
24	EARNED RETURN ON RATE BASE (L23 / L6)		4.5331%	4.7957%	0.0383%		4.5373%	4.7958%	0.0042%
	COST OF SERVICE REVENUE REQUIREMENT								
25	REQUIRED RETURN ON RATE BASE (EQUAL RATES OF RETURN)	6.010%	6.010%	6.010%		6.010%	6.010%	6.010%	
26	REQUIRED OPERATING INCOME (L6*L25)	$391,478,618	$30,989,142	$360,489,476	($36,518)	$391,441,138	$30,951,662	$360,489,476	($37,480)
27	INCOME DEFICIENCY / (SURPLUS) (L26-L23)	$80,449,459	$7,615,470	$72,833,989	($206,516)	$80,411,979	$7,584,400	$72,827,579	($31,070)
28	REVENUE CONVERSION FACTOR (d) (A)	1.649038	1.649038	1.649038	0.000000	1.649038	1.649038	1.649038	0.000000
29	REVENUE DEFICIENCY / (SURPLUS) (L27*L28)	$132,664,214	$12,558,199	$120,106,015	($340,552)	$132,602,409	$12,506,963	$120,095,446	($51,236)
30	RATE SCHEDULE REVENUE REQUIREMENT (L7+L29)	$1,273,517,721	$107,180,007	$1,166,337,714	($340,552)	$1,273,455,916	$107,128,771	$1,166,327,145	($51,236)
31	FUEL REVENUES @ PRESENT RATES (b)		$64,922,446		$0		$64,922,446		$0
32	OTHER RIDERS @ PRESENT RATES (b)		$10,455,485		$0		$10,455,485		$0
33	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L29 / L7)		13.27%		-0.36%		13.22%		-0.05%
34	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L29 / (L7+L31))		7.87%		-0.21%		7.84%		-0.03%
35	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L29 / (L7+L31+L32))		7.39%		-0.20%		7.36%		-0.03%
36	TOTAL REVENUE REQUIREMENT (b) (L8+L30+L31+L32)		$183,252,858		($340,552)		$183,201,622		($51,236)

CERTIFICATE OF SERVICE

I, Shawn McMurray, hereby certify that on March 30, 2017, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Shawn McMurray
Shawn McMurray