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	**)**

DIRECT TESTIMONY OF

William Perea Marcus

on behalf of

THE OFFICE OF ARKANSAS ATTORNEY GENERAL LESLIE RUTLEDGE

January 31, 2017

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ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 16-052-U

DIRECT TESTIMONY OF WILLIAM P. MARCUS ON BEHALF OF THE OFFICE OF ARKANSAS ATTORNEY GENERAL LESLIE RUTLEDGE

I. Introduction

Q. Please state your name, business affiliation and address.

A. I am William P. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q. Please provide your qualifications.

A. My qualifications are attached as Exhibit WM-1. I have over 38 years' experience with energy utility issues. I have previously testified or made formal comments before about forty federal, state, provincial, and local utility and environmental regulatory bodies in the U.S. and Canada on issues including utility restructuring and performance-based ratemaking, revenue requirements, resource planning, and cost-of-service and rate design. I have filed testimony at this Commission on a number of occasions dating back to 1998.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Office of Arkansas Attorney General Leslie Rutledge. I was retained to review a number of aspects of the general rate application filed by Oklahoma Gas and Electric Company ("OG&E" or "the Company").

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

A. In its initial filing, OGE requested a rate increase of $16.5 million. The proposed increase would represent a 9.8% increase in base rate revenue. 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 analysis has identified at least $9.4 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, storm damage costs, and depreciation.

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 49% equity and 51% debt, consistent with the proxy group used by Mr. Hevert. I may revise this information depending on the comparison proxy groups proposed by other parties, including General Staff and Arkansas River Valley Energy Consumers (ARVEC).

2. I recommend inclusion of short-term and variable-rate debt held at the Holding Company level in OG&E's capital structure, 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 5.30% (7.44%, pre-tax), compared to OG&E's update of 5.97% (8.60% 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 $6,299,000.

5. For short-term incentives, the Commission should use year 2015 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 $8,716,000 total company or $824,000 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 $6,544,000 ($618,000 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 base employee-related costs (severance, signing and retention bonuses, and relocation) on a 5.75 year average (2011-2016 YTD), a reduction of $380,000 total company or $35,000 Arkansas jurisdiction.

9. The Commission should use the average from 2011 through the test year for allowing storm damage costs and removing straight-time payroll. This yields an estimate of $696,000. This figure is $410,000 above the $286,000 incurred in the Test Year excluding payroll and $371,000 less than OG&E's estimate (all Arkansas jurisdictional).

10. 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 $1,159,000 total company ($115,000 Arkansas jurisdiction).

11. The Commission should adopt a five-year amortization of rate case expenses, reducing costs by $154,000 (all Arkansas jurisdictional).

12. The Commission should reject OG&E's proposal to raise depreciation expense by $525,000 (Arkansas jurisdiction) to amortize the difference in depreciation reserve over ten years.

13. The Commission should make three adjustments to working capital assets, reducing rate base by $10,003,000 ($830,000 Arkansas jurisdiction and a reduced Arkansas return of $62,000).

14. 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 $312,000 with OG&E's case.

15. 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.

I also provide testimony demonstrating that OG&E has not met its burden of proof that its proposed residential demand charge is cost-based and recommend the rejection of this component of residential rate design.

II. Capital Structure and Rate of Return

A. Debt-Equity Ratio for Financial Capital

Q. Will you please describe OGE Energy Corp. and its relationship to Oklahoma Gas & Electric Company and its other businesses?

A. OGE Energy Corp. ("OGE Energy") is an investor-owned, publicly-traded corporation:

> [OGE Energy] is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations.[1]

Oklahoma Gas and Electric Company ("OG&E") is a wholly-owned subsidiary of OGE Energy. OG&E is an electric utility that generates, transmits, distributes, and sells electric energy in Oklahoma and western Arkansas. OG&E's natural gas midstream affiliate is Enable Midstream Partners, LP ("Enable"). Enable is a partnership between OGE Energy, the ArcLight Group and CenterPoint Energy, Inc. ("CenterPoint"), formed to own and operate the midstream businesses of OGE Energy and CenterPoint.

Q. What is OG&E's capital structure proposal?

[1] OGE Energy Corp. 2015 SEC Form 10-K at page 2.

A. OG&E's proposed capital structure includes 53.11% common equity, and 46.89% long-term debt. It is unclear from Mr. Hevert's testimony what the proposal is based on – whether it is OG&E's interpretation of its actual capital structure or a hypothetical structure. Mr. Hevert finds that the proposal is reasonable based on a comparison of OG&E's proposal with the proxy groups' capital structures.

1. Proxy Group Analysis

Q. How does the capital structure of OG&E compare to the proxy companies used by the company's witness, Mr. Robert Hevert?

A. As shown below, the proxy companies used by Mr. Hevert have, on average, a lower equity and higher debt percentage than OG&E proposes in this proceeding. This causes OG&E's cost of capital and revenue requirement to be overstated.

Q. Did OG&E's presentation of the capital structure of its proxy companies use averaging?

A. Yes. The proxy group companies using Mr. Hevert's methodology produces an average capital structure of 51.68% common equity and 48.32% long-term debt. However, the calculation excludes short-term debt and current maturities of long-term debt which the Commission has typically included.[2]

Q. Will you discuss the appropriate use of a proxy group to analyze the capital structure?

A. The latest available full year of data (through the end of the third quarter of 2016) from OG&E's comparison group again shows lower equity and higher debt percentages than OG&E proposes in this

[2] Testimony of Robert B. Hevert on behalf of OG&E, Exhibit RBH-7

proceeding. I calculated the most recent four-quarter averages for all members of Mr. Hevert's comparison group.

Table 1 below shows the results.

Table 1: Capital Structure of Mr. Hevert's Comparison Companies

	Proxy Company	STD**	LTD	Preferred	Common (w/ STD included in the captial stucture)	Common (w/ STD excluded from capital structure)
ALE	ALLETE, Inc.	2.5%	37.3%	0.0%	60.2%	61.8%
LNT	Alliant Energy Corporation	10.8%	11.9%	0.0%	77.2%	86.6%
AEE	Ameren Corporation	6.3%	45.9%	0.0%	47.9%	51.1%
AEP	American Electric Power Company, Inc.	9.1%	45.0%	0.0%	45.9%	50.5%
AVA	Avista Corporation	5.5%	46.3%	0.0%	48.2%	51.0%
CMS	CMS Energy Corporation	7.1%	62.7%	0.0%	30.1%	32.4%
DTE	DTE Energy Company	3.8%	48.7%	0.0%	47.5%	49.4%
IDA	IDACORP, Inc.	1.1%	44.9%	0.0%	53.9%	54.5%
NWE	NorthWestern Corporation	6.0%	49.5%	0.0%	44.5%	47.3%
OTTR	Otter Tail Corporation	9.3%	39.0%	0.0%	51.7%	57.0%
PNW	Pinnacle West Capital Corporation	4.9%	42.4%	0.0%	52.7%	55.4%
PNM	PNM Resources, Inc.	11.0%	49.9%	0.0%	39.1%	43.9%
POR	Portland General Electric Company	3.0%	47.9%	0.0%	49.2%	50.7%
SCG	SCANA Corporation	5.5%	49.4%	0.0%	45.2%	47.8%
XEL	Xcel Energy Inc.	4.7%	52.3%	0.0%	43.1%	45.2%
	Average	6.0%	44.9%	0.0%	49.1%	54.2%
	Adjusted avg. *	**6.0%**	**44.9%**	**0.0%**	**49.1%**	**54.2%**

* Assigning 50% of preferred stock to debt and 50% to equity
** Includes current maturity of long-term debt
Source: Yahoo! Finance (average of quarterly balance statements, four quarters ending September 30, 2016).

When short-term debt is properly included in the capital structure, Mr. Hevert's comparison group has 49.1% common equity and 50.9% debt. The inclusion of short-term as well as long-term debt in the capital structure is reasonable because many utilities routinely use relatively large portions of short-term debt to finance their operations, including construction work in progress and other assets, as well as to cover recurring fluctuations in revenue and expenses. It amounts to 6.0% of the financial capital funding for the proxy group.

Q. Would using a hypothetical capital structure containing more debt harm OG&E?

A. No. The hypothetical capital structure would be based on other companies of comparable risk with less equity in their capital structures and consistent with the sample used for the cost-of-equity assessment. This ratemaking adjustment has been found reasonable and ordered by the Commission for many years.

Q. Has the Commission generally supported the use of hypothetical capital structures, especially for wholly-owned subsidiaries, like OG&E?

A. Yes. It amended a partial settlement last year to add 200 basis points to debt and subtract it from equity, shifting SourceGas from 50-50 debt/equity to 52-48 debt/equity. The Commission provided a very clear explanation in Docket 15-011-U:

> 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. The evidence of record supports imputing the average capital structure of companies with comparable risk to SGA for the purposes of determining SGA's overall cost of capital. Imputing a capital structure based on SGA's parent company, SG LLC, would be inappropriate, as the intent of the imputation is to capture the risks inherent for a company similar to SGA, not SG LLC. Accordingly, the Commission finds that an adjustment to the proportions of debt and equity used as the imputed capital structure to calculate the overall cost of capital for SGA is appropriate. The Commission finds that an adjustment from 50% debt and 50% equity to 52% debt and 48% equity will better align the approved overall cost of capital for SGA with the average risks of its peers. As a result, the Commission finds that the WACC and the weighted cost of debt for SGA should be recalculated and

> the revenue requirement for SGA should be updated before new rates take effect.
>
> It is the Commission's opinion that approval of the settlement without this adjustment would violate the standard of congruence consistently upheld by the Commission, and it would improperly favor the interests of shareholders over the interests of ratepayers.[3]

Q. What is your recommendation?

A. I recommend that OG&E's rate of return for ratemaking purposes be based on a hypothetical capital structure of 49% equity and 51% debt, consistent with the proxy group used by Mr. Hevert. I may revise this information depending on the comparison proxy groups proposed by other parties, including Staff and ARVEC.

2. Short-Term Debt in the *Pro Forma* Capital Structure

Q. Will you compare the capital structure of OG&E and OGE Energy?

A. The capital structure of OG&E has more equity than that of OGE Energy, and OGE Energy has the entire corporation's short-term debt and variable-rate long-term debt.

Table 2: Financial Capital Structure of OGE Energy and OG&E[4]

[3] Order No. 10 in Docket 15-011-U, pp. 13-14.
[4] OGE Energy Second Quarter 2016 Financial Report (OGE Energy and OG&E liability statements), 6th and 11th unnumbered pages. The Second Quarter reports were used for consistency with material submitted by the Company in updated Schedule D. Downloaded from: http://phx.corporate-ir.net/phoenix.zhtml?c=106374&p=irol-reportsannual

	OGE Energy	%	OG&E	%	All but OG&E	%
Long-term debt *	2,630	42.2%	2,530	44.3%	100	18.8%
Short-term debt	284	4.6%	-	0.0%	284	53.6%
Equity	3,322	53.3%	3,176	55.7%	146	27.6%
ADIT	2,315		1,669		645	
Other liabilities	1,110		1,005		105	
* including payable in less than one year						

Q. How much short-term debt should be included in OG&E's *pro forma* capital structure?

A. It appears that OG&E itself has a significant amount of short-term debt, but all of that debt is intra-corporate (*i.e.*, lent to the holding company).[5] In addition, OGE Energy has outside short-term debt. I have included $171,700,000 of short-term debt, the quarterly average of the last four quarters of outside debt at the holding company level ending on September 30, 2016. This is 2.79% of the financial capital structure of OG&E, but less than half of the amount of other comparable utilities in Mr. Hevert's sample.

Q. What does this mean for long-term debt?

A. By subtraction, it is 51% minus 2.79% or 48.21%.

B. Cost of Debt

1. Long-Term Debt Cost

Q. How does OG&E propose to set the cost of long-term debt?

A. Based on actual debt issuances of OG&E.

Q. Do you recommend any adjustments?

[5] *See* APSC-86.01.

A. Yes. I include $100 million of long-term variable-rate debt at the holding company, which otherwise would allow OGE Energy to use lower-cost debt to leverage investments in OG&E or finance unregulated investments such as the company's shares in Enable, which are clear cases where shareholders benefit at the expense of ratepayers. I recommend a 2.17% interest rate for this debt, which is 75 basis points above the level recorded in June 2016, to reflect the potential for three Federal Reserve interest rate hikes through the end of the pro forma year (one of which has already occurred).

Q. What is the effect of this change?

A. It reduces OG&E's cost of long-term debt from 5.47% to 5.36%.

2. Short-Term Debt Cost

Q. Will you discuss the forecasted cost of short-term debt for OG&E?

A. I recommend a rate of 1.51%, which is 75 basis points higher than the pro forma year debt rate used by OG&E, which is the same increase that I am proposing for variable-rate debt.

C. Return on Equity (ROE)

1. Introduction

Q. What ROE is OG&E requesting?

A. Company Witness Mr. Hevert estimates that OG&E's cost of equity falls within the range of 10.0% to 10.75%, and suggests a point estimate of 10.25% for the company's ROE in this case.[6]

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[6] Direct Testimony (Hevert), p. 4 (lines 16-18).

Q. Upon what analytical results does Mr. Hevert base his range and recommendation?

Mr. Hevert's average Discounted Cash flow (DCF) results range from 8.68% to 10.12%.[7] Mr. Hevert also includes values for "Mean Low" and Mean High" results. The Mean Low and Mean High results should be ignored. They represent the extreme outliers of the proxy group results. Although he does not state it explicitly, Mr. Hevert would have the Commission ignore the extreme low results and instead focus on the extreme high, Mean High, results. This is unreasonable.

Mr. Hevert also obtains results for his version of the Capital Asset Pricing Model (CAPM)—which he calls the Market Risk Premium approach—that range from 8.84% to 11.40%.[8] However, this method relies upon a methodology—the derivation of the assumed, *ex ante* (*i.e.*, forward-looking) market risk premium with the application of the DCF method—which is inappropriate for reasons that will be explained further on.

Finally, Mr. Hevert obtains a third set of estimates, which range from 10.03% to 10.39%,[9] using what he calls a Bond Yield Plus Risk Premium approach. This approach inappropriately relies on ROE authorizations from other jurisdictions, a reliance that both is based on circular logic and requires the Commission to abdicate its authority to set just and reasonable rates for OG&E's customers.

Q. What is the ROE currently authorized for OG&E?

A. On June 11, 2011, the Commission approved an all-party settlement which authorized an ROE of 9.95%,[10] which was a decrease from the

[7] *Id*., pp. 25 (Table 2) and 33 (Table 5).
[8] *Id*., p. 37 (Table 6).
[9] *Id*., p. 41 (Table 7).
[10] Docket No. 10-067, Settlement Agreement, p. 3, Order #6.

10.25% that was adopted on May 20, 2009.[11] The authorized ROE before 2009 was 10%.[12]

Q. What ROE do you recommend?

A. Subject to review of the DCF testimony of other parties, including the Staff, I consider 8.7% to 9.5% to be the endpoints to a range of reasonableness. This range incorporates a portion of Mr. Hevert's DCF results (using his Mean case), which range from 8.7% to 9.3%.[13]

Based on the information in the balance of this testimony, including information from professional, academic, pension actuarial, etc., sources, I believe that CAPM and similar analyses point toward a range of 8.0% to 9.0%.

I recognize, however, the Commission's historical reliance on DCF analysis, so that I see the CAPM analysis that I have prepared as supporting a downward move from the DCF mid-point. The December authorizations for electric and gas utilities ranged from 8.64% to 10.10%[14]. Therefore, I would recommend 9.30% as a reasonable estimate, subject to review of the DCF results of other parties, including the Staff, before considering the formula rate plan. If the Formula Rate Plan (FRP) Rider were to be adopted, I would recommend a 25-basis point further reduction to 9.05%, because the FRP Rider and OG&E's other riders will make sure there is little or no regulatory lag and greatly reduce the Company's business risk.

This recommendation is also dependent on the congruence between the capital structure of the proxy group and the capital structure allowed

[11] Docket No. 08-103-U, Order #6, p. 6.
[12] Docket No. 06-070-U, Settlement Agreement, p. 3.
[13] As noted above and will be explained in more detail below, Mr. Hevert's Mean Low and Mean High results should be disregarded.
[14] Market Intelligence. A flurry of rate case decisions hit in Dec. 2016. Accessed: marketintelligence.spglobal.com/our-thinking/news/a-flurry-of-rate-case-decisions-hit-in-dec-2016.

for OG&E. Any increases in the equity percentage of OG&E above the 49% that I recommend should be met with reductions in the return on equity.

2. Upward Bias of OG&E's ROE Case

Q. Mr. Hevert's average DCF results range between 8.68% and 10.12% but the range of reasonableness that the witness proposes is 10.0% to 10.75% with a point estimate of 10.25%. Please summarize the witness's reasoning.

A. Mr. Hevert asserts that the capital market conditions (primarily risk of increasing interest rates) should cause the Commission to use caution when considering the DCF results generally, the Constant Growth version, in particular, and indicates that the Commission should generally give more weight to his CAPM and Risk Premium methods).[15] Mr. Hevert also relies on OG&E's capital program, including an environmental component, and flotation costs as reasons to increase OG&E's ROE. These are addressed below.

a. Capital Market Conditions

Q. Please summarize Mr. Hevert's position.

A. Mr. Hevert essentially raises the issue of rising interest rates, suggesting the Commission give less weight to the Constant Growth DCF method.

Q. What is your response?

A. While interest rates are rising, I do not agree that the Commission should disregard DCF results. I generally leave it to Staff to develop

[15] Hevert, p. 61 (lines 17-20).

DCF results with updated inputs, which I do again here. I will make some comments on interest rates.

Q. Compare the current and projected (near-term) 30-Year Treasury yields that Mr. Hevert used when OG&E filed its testimony on August 28, 2016 and the yield as it exists today.[16]

A. The 30-day average Treasury yield was about 2.35% last August; the projected (near-term) yield was 3.0%.[17] By comparison, the current 30-day average, 30-year Treasury yield is now about 3.11%,[18] representing an increase of 76 basis points.

Q. Did the Fed raise the Federal Funds rate in December?

A. Yes. The Fed raised the Federal Funds rate by a ¼ of a point on December 14,[19] and indicated that it thought it might make three more in 2017,[20] with many believing that the first would be in June.

It is clear, therefore, that the Fed has finally found cause to begin raising interest rate targets. The questions now regard how fast and by what amount the 30-year Treasury yield might change further within the relevant timeframe.

Q. Please discuss the speed of possible Fed rate hikes.

A. There appears to be a wide range of viewpoints, both from within and outside of the Fed regarding the question the haste that the Fed might take to raising interest rates. The Bureau of Labor Statistics released the December jobs report on January 6, which showed unemployment

[16] 30-day average, ending on January 4, 2016.
[17] Direct Exhibit RBH-15.
[18] Calculated from raw data collected from the U.S. Treasury.
[19] Federal Reserve press release, December 14, 2016.
[20] MarketWatch, 1/6/17: Wage growth may spur Fed into quicker action. Available: www.marketwatch.com/story/wage-growth-may-spur-fed-into-quicker-action-2017-01-06.

essentially holding steady at 4.7% and wage growth rising to a seven-year high of 2.9% (year-on-year).[21]

On the one hand, the pace of wage growth, supported by the fact that unemployment has fallen to or at least near sustainable levels and the inflation rate is beginning to close in on 2%, which is the Fed's inflation target, have led some, both inside and outside of the Fed, to believe there will be more than three increases to the Federal Funds rate this year with the first coming in March—before the original expectation of June.[22]

On the other hand, some, again including people both inside and outside the Fed, appear less swayed that gradualism is not still warranted. For example, the Dallas Fed President, while sounding a bit uncertain whether the Fed would be able raise interest rates gradually, also stated, "I think we can do it gradually and patiently."[23]

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[21] CNBC, 1/6/17: US Treasury's fall after weaker-than-expected jobs report. Available: www.cnbc.com/2017/01/06/bond-investors-gear-up-for-jobs-report.html.

[22] See, *e.g.*, MarketWatch, 1/6/17:

Wage growth may spur Fed into quicker action. Available: www.marketwatch.com/story/wage-growth-may-spur-fed-into-quicker-action-2017-01-06.

Interest rates may have to rise 'briskly,' Richmond Fed president says. Available: www.marketwatch.com/story/interest-rates-may-have-to-rise-briskly-richmond-fed-president-says-2017-01-06.

Wage growth may spur Fed into quicker action. Available: www.marketwatch.com/story/wage-growth-may-spur-fed-into-quicker-action-2017-01-06.

Interest rates may have to rise 'briskly,' Richmond Fed president says. Available: www.marketwatch.com/story/interest-rates-may-have-to-rise-briskly-richmond-fed-president-says-2017-01-06.

[23] MarketWatch, 1/6/17: Fed's Kaplan sounds note of doubt about gradual rate hikes. Available: www.marketwatch.com/story/feds-kaplan-sounds-note-of-doubt-about-gradual-rate-hikes-2017-01-06.

Q. Please discuss the future level of 30-year Treasuries.

A. Blue Chip Financial Forecasts forecasted in June 2016 that the 30-year Treasury yield would reach 3.90% by 2018. This is the forecast that Mr. Hevert uses in his August testimony.

Q. Do you have any further comments on 30-year Treasury yields?

A. Yes. I reviewed the latest information on 30-year Treasury Inflation Protected Securities and compared them with the 30-year bond rates. The most recent month of 30-year TIPs yielded 1.04%, while the Treasury bond yield was 3.11%, suggesting that the market viewed long-term inflation would be in the 2% range.[24]

While these rates are indeed a little higher than those experienced earlier in the year, they are very close to the average results experienced over the last four years (1.02% and 3.06%).

More importantly, they are quite a bit lower than the rates in place at the time of the last OG&E rate case, when the Commission adopted a settlement with a 9.95% rate of return. The average rates for the first 3 months of 2011 (when Staff and intervenor testimony was filed) were 2.00% for TIPs and 4.56% for regular 30-year Treasuries (inflation expectation of about 2.5%). Even the 3.9% rate suggested by Blue Chip is well below the 30-year Treasury rate at the time of the last rate case.

Q. What do you conclude?

A. I realize that by now the Blue Chip Financial Forecasts forecast could be stale and expect that Mr. Hevert will supply a more up-to-date forecast in his rebuttal testimony. Moreover, more information about

[24] Near-term inflation expectations are in the range of 1.8%. The five year TIPs yielded 0.15% in December, while the five year Treasury was at 1.96%.

the Fed's intentions regarding rate-increase gradualism will be available as the case progresses. Nevertheless, I do not see significant changes at present from the recent past, and even forecast changes are below the rates in place at the time of the last rate case.

At the moment, I propose using both 3.9% and 5.0% in our normal CAPM sensitivity analysis (below) in order to show Mr. Hevert's Blue Chip forecast as well as one that is more conservative to the high side. I do not necessarily believe that either of these sensitivity-analysis figures is a reasonable estimate to use for setting rates, but am including them for information only.

b. OG&E's Business Risk and Other Considerations

Q. Please summarize Mr. Hevert's assessment of OG&E's business challenges.

A. Mr. Hevert judges OG&E to face elevated business challenges as compared to the sample companies on the basis of (1) investments in assets required to meet environmental regulations; [25] and (2) general pressure on cash flows from its general capital investment plan.[26] Furthermore, Mr. Hevert asserts that neither the DCF model nor CAPM account for flotation costs,[27] and the cost-recovery mechanisms that OG&E enjoys do not reduce its cost of capital because such mechanisms are common across the industry and, as such, their benefit is imbedded in the cost of capital that the proxy companies exhibit.[28]

[25] Hevert, p. 42 (lines 22-23)
[26] *Id.*, p. 49 (lines 20-21)
[27] *Id.*, p. 51 (lines 16-18)
[28] *Id.*, p. 54 (1-17)

i. Capital Spending Plan

Q. What are Mr. Hevert's claims regarding OG&E's upcoming capital-spending plan and its effect on cost of capital?

A. Mr. Hevert observes that OG&E's capital program during period 2016-2020 is about $2.85 billion,[29] and characterizes such a program as "significant."[30] The witness concludes that the "significant" program "will place additional pressure on its cash flows making regulatory support more important in terms of OG&E's ability to finance these expenditures and earn a reasonable return on its planned investments."

Q. Is the $2.85 billion worth of capital expenditures substantially elevated when compared to OG&E's historical spending?

A. No. In fact, it is somewhat modest. $2.85 billion over five years[31] equates to $570 million per year, on average. By comparison, OG&E's average, annual capital spend from 2011-2015 was $730 million; the 2011 and 2013 expenditures were $878 million and $846 million, respectively.[32]

Table 3: OG&E's Historical Capital Spending, 2011-2016 (YTD)

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[29] *Id.*, p. 44 (lines 3-4).
[30] *Id.*, p. 46 (line 8).
[31] *Id.*, p. 44 (lines 3-4).
[32] AG DR 11-16_Att.

Year	Capital Expenditures
2011	$877.7MM
2012	$705.6MM
2013	$846.0MM
2014	$573.8MM
2015	$649.8MM
2016 (YTD*)	$590.5MM
Average (full years)	**$730.6MM**

* OG&E did not provide the date which the 2016 expenditures run through.

Source: AG DR 11-16 Att.

Based upon the historical data, OG&E clearly has the capacity to undertake a more modest program without increasing its current risk profile.

Q. How does Mr. Hevert include credit rating agencies in the discussion?

A. The witness says that credit ratings agencies recognize the risk associated with increased capital expenditures. As support for the general idea that ratings agencies recognize the risk associated with elevated capital spending, Mr. Hevert quotes S&P, which speaks specifically to the risk of <u>delayed</u> or <u>partial</u> recovery of capital expenditures. However, credit ratings agencies that specifically cover OG&E have said they have confidence that the utility's regulators will provide the necessary authorizations for the capital program and therefore see moderate and short-lived risk associated with the program. For example, Moody's says:

> The execution of these projects and securing timely cost recovery for investments of this magnitude, duration and importance is the greatest challenge to OG&E's credit profile over the next four years. … Going forward, we

expect that the company will receive timely cost recovery of its environmental expenditures....[33]

In other words, the correct question for Mr. Hevert to ask is whether OG&E's regulators are credit supportive insofar that they provide timely recovery. If the answer were "no," it would then be time to ask whether the utility's cost of capital was elevated. However, as we just saw from the Moody's quote above, credit ratings agencies believe that OG&E's regulators will provide timely cost recovery and, as such, OG&E should not expect its cost of capital to rise as a result of the capital spending program.

Q. Mr. Hevert notes that OG&E believes that the risks associated with its capital program are of sufficient interest to merit disclosure on its SEC 10-K filings. Please discuss.

A. The 10-K filing passage that Mr. Hevert provides includes, in part, "We may not be able to recover the costs of our substantial planned investment in capital improvements and additions." It also references large infrastructure replacement and environmental programs as being drivers of the capital spending. The interesting thing about this is that OG&E has been including the *exact same statement* in its 10-K filings since it filed its 2007 10-K. Since then, the company has been able to access capital, despite ROE authorizations that were as low as 9.95% and were at 10.25% for just a brief time at around the time of the financial crisis.

Q. Has Mr. Hevert compared the level of OG&E's capital program to those of the proxy companies?

A. No, he has not. In response to a request for such an analysis, OG&E stated that Mr. Hevert's discussion of capital expenditures was not a

[33] Moody's Investor Service. Credit Opinion, October 28, 2016.

comparative analysis.[34] However, not making such analysis means that OG&E has not met its burden to prove that any challenges it faces are unusual and not equally faced by the companies in the proxy group. If the company does not or cannot make such a showing then the Commission must conclude that the risks faced by OG&E are similar in nature and intensity as those that the proxy group faces and no additional adjustment is reasonable.

ii. Flotation Costs

Q. Please summarize the conclusion Mr. Hevert draws from his observations about flotation-cost effects.

A. While the witness estimates a flotation-cost effect of 0.11%,[35] he has not specifically included the estimate in his ROE recommendation. Rather, Mr. Hevert generally claims that the Commission should consider the effect of flotation costs when determining where the ROE point estimate falls within the range of results.[36]

Q. Please discuss Mr. Hevert's case regarding flotation costs.

A. Mr. Hevert claims the following regarding flotation costs:

> Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, remain part of the cost structure that exists during the test year and beyond, and should be recognized for ratemaking

[34] AG DR 11-19.
[35] Hevert, p. 53 (lines 6-8).
[36] *Id.* (lines 11-13).

> purposes. Therefore, recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such cost recovery may deny OG&E the opportunity to earn its required rate of return in the future.[37]

We note that Mr. Hevert's flotation cost calculation for OG&E is based on costs incurred in the past by companies in his comparison group,[38] not on any costs that the Company claims in either the test or *pro forma* years.

Mr. Hevert claims that the Commission and the Staff have recognized the need to recover flotation costs in prior orders, citing Staff's estimation of a five-basis-point flotation-cost estimate and the Commission's approval of such arguments in its Order in the 2004 AWG rate case.[39] However, Mr. Hevert has overstated both Staff and the Commission's past support for the inclusion of flotation costs.

The Commission agreed in the 2004 AWG case that prospective flotation costs may be reasonable when they can be shown to be "valid, sustainable, measurable, and material,"[40] but refused to adjust for flotation costs incurred in the past. It stated as follows regarding any historical flotation costs: "The Commission finds such treatment of prior 'unrecovered' costs inappropriate in setting prospective rates."[41]

Mr. Hevert's addition for flotation costs is based on *past* costs incurred by companies that were not even the target company. Therefore, such an estimate cannot be considered "valid, sustainable, measurable, [or] material" for OG&E and in any event it is for past costs by other companies. The Commission should give Mr. Hevert's testimony

[37] *Id.*, pp. 50 (starting at line 16) – 51.
[38] *Id.*, Exhibit RBH-8.
[39] *Id.*, pp. 51 (starting at line 14) – 52.
[40] *Id.*, Order 6, p. 34.
[41] *Id.*

regarding flotation costs no weight, even to judgmentally adopt a higher ROE than would be yielded by base methods.

D. Validation of Return on Equity Recommendation

Q. How does Mr. Hevert attempt to validate his ROE recommendation?

A. Mr. Hevert attempts to validate his ROE recommendation in this case by comparing it to ROE authorizations from jurisdictions near Arkansas and around the country.

Q. What is Mr. Hevert's argument regarding the appropriateness of the inclusion of such data?

A. The witness claims that the inclusion of such data is "consistent with [Arkansas] Act 725 [and]…Arkansas Code Section 23-4-410."[42]

Without context, however, authorizations of other jurisdictions are dispositive of nothing in the instant case. The Missouri Public Service Commission (MPSC) recently explained why this is so:

> [The Office of Public Counsel (OPC)] cites a rule of reasonableness that checks the reasonableness of a decision by comparison with other decisions. But the other decisions that OPC cites are from other States.[footnote omitted] Those citations are less persuasive than past Commission decisions because, not only has OPC shown nothing about the controlling facts in those decisions, OPC has shown nothing about the controlling law. OPC has not shown that the cited decisions are comparable. [Footnote omitted][43]

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[42] *Id.*, p. 62 (lines 14-16).

[43] MPSC, Report and Order In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs to Increase Its Annual Revenues for Natural Gas Service (MPSC File No. GR-2014-0086), pp. 50-51.

Q. Please discuss Mr. Hevert's validation process.

A. Mr. Hevert lists 42 ROE authorizations from Arkansas-proximal and South East jurisdictions between 2011 and 2015 and states that over half of them had ROE authorizations of at least 10%. However, 33 of the 42 authorizations the witness includes are too old to be "current" (*i.e.*, from 2011-2013) and in any case averaged 10.08%. Only nine are from 2014-2016, whose average is 9.76%; the 2015-2016 average is even lower at 9.56%.

Table 4: Regional ROE Authorizations

Year Range	Average
2011-2013	10.08
2014-2016	9.76
2015-2016	9.56

Mr. Hevert's own data show a downward trend. Not only is the period 2011-2013 not current—current estimates are a requirement of Act 725 when citing to extra-jurisdictional authorizations—the information shows that if anything the perception of the correct ROE has declined in recent years. If the Commission is going to consider the Arkansas-proximal, extra-jurisdictional information, at all, the most contemporaneous average from the data Mr. Hevert presents ranges from 9.56%-9.76%.

Q. Please discuss the use of 10% as the comparison of interest.

A. As noted, Mr. Hevert indicates that more than half of the ROE authorizations were greater than 10.0%. However, OG&E is proposing an ROE authorization of 10.25%, which would be the more appropriate comparison. Just 11 of the 42 samples from 2011-2016 where set at least 10.25%, which means 31 were below 10.25%. Moreover, just one out of nine was 10.25% or more between 2014 and 2016.

Q. What about Mr. Hevert's use of nationwide electric cases since June, 2014?

Mr. Hevert reviewed return authorizations for electric utilities since July 2014. The first thing to note is that two-thirds of the utilities had return authorizations that were less than 10%. Mr. Hevert has given no reason to believe that the one-third of authorizations that were at least 10% were cases of sufficient similarity to this case to warrant more consideration than the two-thirds where the authorization was below 10%.

Secondly, just as with the regional utilities, it would have been more informative to ask about the number of ROE authorizations above 10.25%.

Lastly, we note that there were 25 rate decisions issued in December, 2016. Those decisions produced published ROE authorizations that ranged from 8.64%-10.10%.[44]

If the Commission is going to rely on extra-jurisdictional ROE authorizations at all in this rate case it must observe and consider the foregoing infirmities to Mr. Hevert's misleading framing when doing so.

Q. Did Mr. Hevert inappropriately use an investment analytics firm to admonish the Commission?

A. Yes. The witness references Regulatory Research Associates' (RRA) commission rankings, stating that Arkansas falls within the "Average" group (*i.e.*, 9.69%) and that only if Arkansas would elevate the ROE to 10.36% could it achieve "Above Average" status.

[44] S&P Global Market Intelligence. Available on the web at marketintelligence.spglobal.com/our-thinking/news/a-flurry-of-rate-case-decisions-hit-in-dec-2016.

Firstly, RRA's parent company's main job is to serve investors.[45] And while RRA, itself, does some work that it says is intended to assist regulators, the ROE rankings are cast as part of its financial focus.[46] Mr. Hevert, himself, also concedes that the ranking of ROEs is from the investor's perspective.[47]

Secondly and more importantly, "Average" rather than "Above Average" is clearly a better place to be from a regulator's perspective, all else equal, because it appropriately reflects the competing interests of both shareholders and ratepayers.

E. Information from the Real World

Q. Do you have any further comments on the analysis of ROE that Mr. Hevert conducted?

A. Yes. I have two general comments. First, the Commission should reject inflated estimates of investors' alleged expectations and unjustified methodologies that inflate the rate of return.

Second, as noted above, the Commission must not forget that the purpose of this case is to set a return on equity for the regulated operations of an electric utility, and must prevent higher returns from unregulated activities from influencing its decisions.

Q. Have you developed some additional information to examine the requested return on equity?

A. Yes. It is valuable for the Commission to look beyond the calculation of competing mathematical models when considering the return on equity

[45] The parent, S&P Global Market Intelligence, states on its website: "We deliver the data and insight you need to make informed, smarter business decisions and investment decisions that are critical to your future." Accessed: marketintelligence.spglobal.com/about-us/about-us.html.
[46] RRA, 2015. Accessed: www.snl.com/Documents/Energy/RRA_Brochure.pdf.
[47] Hevert, p. 63 (lines 6-8).

and look at what utilities and analysts are saying about the stock market when they are **not** trying to convince regulatory commissions to give them a specific return on equity.

Several sources of this kind of information include data presented by utilities in their roles as pension fund managers and multi-billion-dollar investors in nuclear decommissioning funds. In the context of investing in these funds, many utilities are, in fact, trying to convince regulatory commissions to give them more money by providing very low estimates of equity returns on their own investments.

Q. Have you looked at equity return estimates in the pension field?

A. Yes, I have analyzed the equity return estimates made by actuaries when setting parameters for the rate of return on assets used in calculating funding for pensions and other post-retirement benefits (OPEBs).

Utility annual reports contain the data that are used to make these assumptions, including (1) the expected return on assets invested in the pension plan, and (2) the target and actual percentages of debt and equity investments. Even though many of the annual reports do not state expected earnings by asset class, they do provide the overall fund earnings expectation in addition to the fund managers' asset-class target allocation.

Q. How have you used this information?

A. I have calculated the implicit equity return on the pension funds of all of Mr. Hevert's comparison companies. One can look at other companies by making the simplifying assumption that the returns on US stocks, international stocks, and real estate are similar over the long run (an assumption that will not have a large impact on the results because of relatively small quantities in international stocks and real estate). Based on this assumption, one can estimate the stock market return that would result with a bond return of, for example, 5%. In this analysis, for each utility I set the bond return equal to the discount rate that the pension actuary uses to calculate annual pension costs (generally the actuary uses the corporate bond rate). This method also calculates the equity risk premium (over corporate debt) for each company by using their own debt return estimates. The estimates of the comparison group's pension actuaries yield an average equity return for the broad stock market of 8.91% with an implied risk premium relative to corporate bonds of 4.68%. Table 5 shows this comparison and the average return.

Table 5: Pension Return Assumptions for Comparison Companies

Proxy Company	Discount Rate	Pension Return	Equity Ratio	Debt Ratio	Cash Ratio, if Stated	Equity Return (debt @ discount rate, cash @ 3%)
ALLETE, Inc.	4.30%	8.00%	61.0%	39.0%	0.0%	10.37%
Alliant Energy Corporation	4.18%	7.60%	70.0%	30.0%	0.0%	9.07%
Ameren Corporation	4.00%	7.25%	57.5%	40.0%	2.5%	9.70%
American Electric Power C	4.30%	6.00%	40.0%	59.0%	1.0%	8.58%
Avista Corporation	4.21%	5.30%	37.5%	62.5%	0.0%	7.12%
CMS Energy Corporation	4.52%	7.50%	70.0%	30.00%	0.0%	8.78%
DTE Energy Company	4.12%	7.75%	75.0%	25.0%	0.0%	8.96%
IDACORP, Inc.	4.25%	7.50%	76.0%	24.0%	0.0%	8.53%
NorthWestern Corporation	4.23%	5.80%	40.0%	60.0%	0.0%	8.16%
Otter Tail Corporation	4.35%	7.75%	62.4%	37.6%	0.0%	9.80%
Pinnacle West Capital Corp	4.02%	6.90%	42.0%	58.0%	0.0%	10.88%
PNM Resources, Inc.	4.48%	6.80%	35.0%	65.0%	0.0%	11.11%
Portland General Electric C	4.02%	7.50%	67.0%	33.0%	0.0%	9.21%
SCANA Corporation	4.20%	7.50%	67.0%	33.0%	0.0%	9.13%
Xcel Energy Inc.	4.66%	6.87%	58.0%	40.0%	2.0%	8.53%
Average	**4.23%**	**7.03%**	**58.9%**	**40.7%**	**0.4%**	**8.91%**
Risk Premium Relative to Corporate Bonds						**4.68%**

Source: Data taken from utility 2016 10-Ks.

Q. Please comment on how the expected return of pension funds relates to the return that prospective investors in utilities "require."

A. Explicitly defining the two terms is helpful:

- "Expected" return is the weighted-average most likely outcome of an investment in a particular security or portfolio of securities.
- "Required" return is the minimum return that an investor requires to compensate him for assuming a given level of risk.

Pension and decommissioning funds' stated expectations for returns from equities in which they have invested must be greater than or equal to their required returns for the stock market or the individual stocks they hold. Otherwise, their managers would not have invested in those individual stocks. If they did not like the "expected" return for the market as a whole, the managers would theoretically shift to a portfolio with more fixed-income securities—all the way up to a ratio of 100% if they did not like the expected return of any stocks. Even though they could choose to invest a higher percentage in fixed-income securities, funds vote with their dollars to stay heavily invested in the stock market because the expected return is at least as great as the minimum return that they require to assume for the level of risk they are assuming. These managers make such decisions even with lower returns than those that Mr. Hevert believes are "required."

In essence, fund investors are matching their "requirements" to their "expectations." They simply do not "require" a return of 10.25% for a utility company with a lower beta than the market when long-term

Treasuries are 2.35%, as they were when Mr. Hevert collected his data,[48] given that they are voting with their dollars.

Instead, pension funds can provide dollars to retired workers with fewer contributions by corporations and governments by staying in the market despite their stated (average) down-economy "expectations" of 9.70% equity returns and 5.39% corporate bond returns, which corresponds to a risk premium (geometric mean) of 4.31%.[49]

In sum, to determine the required return one can look at what market participants are actually doing with their own money in the face of their current expectations.

Q. Does the Russell Investment Group use the same types of mathematical techniques that Mr. Hevert and other analysts use to estimate future stock market returns?

A. Yes. In particular, Russell uses a modified discounted cash flow methodology, which it calls the dividend discount model, to derive an equity risk premium. Russell's analysis suggests a stock market return of **9%**, composed of 3% inflation, a 3% real return on government bonds, and a 3% equity premium. The real equity return is divided into two components, an average long-term dividend yield of 2.3% and real earnings growth of 3.9% – components that are very similar to those used in a DCF method.

[48] They are averaging (on a monthly basis) 3.11%.

[49] Moreover, because of the standards written into the Employee Retirement Income Security Act of 1974 ("ERISA", a Federal law that establishes minimum standards for pension plans in private industry and provides for extensive rules on the federal income tax effects of transactions associated with employee benefit plans), we can reasonably assume that pension fund managers are providing those returns at a level of risk that they deem prudent. Pension fund behavior in the face of current expectations of relatively low equity returns shows that those low returns meet or exceed their "required return" on equity investments.

1. Other Information on Stock Market Returns

Q. What information can you bring to bear from other market participants on future stock market returns?

A. A considerable amount of information in the popular press and the academic literature suggests that stock market returns are likely to be less now than in the past and the risk premium of stocks over bonds is relatively low. The information we present here supports the proposition that OG&E's risk-premium and market return expectations are well above reasonable; it is, therefore, important to compare the results that the information that follows suggests with the high equity-return expectations – *i.e.*, 10.25% – that OG&E is requesting in this case.

Q. What information have you found from investment professionals?

A. There are many examples in the popular financial press of more sober market-return expectations for utilities and the broader stock market. We offer a few here.

- Commentary from Janus Capital on March 30, 2016[50] states:

> …30-40% of developed bond markets [and 75% of Japanese JGBs] now have negative yields… . … All financial assets are ultimately priced based upon the short term interest rate, which means that if an …[investor in a bond with negative interest rate] loses money [at redemption], then a stock investor will earn much, much less than historically assumed or perhaps might even lose money herself. Yields have been at 0% or negative for years now across most developed markets and to assume that high yield bond and equity risk premiums as well as P/E ratios have not adjusted to this Star Trek

[50] Full commentary attached in Exhibit WM-5.

> interest rate world is to believe in – well to believe in Zeno's paradox.[51]

- Participants in Barron's 2012 Roundtable, Part One—Listen Up Class: Here's How to Profit[52] stated the following:

> Money flowed into the utility area as investors sought higher current returns. Also, there were seven or eight deals in the sector.[53]
>
> …
>
> Utilities pay big dividends because they continually are granted a 10% return on equity by regulators in a world where returns are moving much lower. After earning 10% they can pay out 4% to 5% to investors.[54]

- In July, 2012, PIMCO's legendary bond investor, Bill Gross, said that a 7% return, which is what many US investors such as pension funds are assuming as a minimum return is unlikely in what PIMCO calls, "the new normal."[55]

- The Wall Street Journal reported results of interviews of investment experts from various institutions, including the Ford Foundation, the Vanguard Group, and the London Business School. Asked what return they would accept (over the long-term after inflation, expenses and

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[51] Zeno, the commentary states, was an ancient Greek who posed the following conundrum: "Imagine a walker heading towards a finish line 10 yards away but every step he took was half of the length of the step he took before. If so, even if he walked an infinite amount of steps he could never reach his destination. Mathematically correct but the real world resolution was that Zeno's walker and everything else that we experience moves forward in full step integers as opposed to fractions. It was a mathematical twist only."

[52] Available: online.barrons.com/article/SB50001424052748703535904577152932179268296.html?mod=BOL_twm_ls#articleTabs_article%3D1.

[53] Barron's 2012 Roundtable Panelist, Mario Gabelli, Chairman and CEO of Gamco Investors Inc. Gamco Investors, Inc. manages assets worth $34.0 billion, according to its 2011 Annual Report (available: www.gabelli.com/Gab_pdf/GBL2011_rpt.pdf).

[54] Barron's 2012 Roundtable Panelist, Bill Gross, Founder and Co-Chief Investment Officer of Pimco. Pimco manages $3.45 trillion in assets (internally ($1.92 trillion) and third-party client assets ($1.53 trillion)) and was founded in 1971, according to its Website (www.pimco.com/EN/OurFirm/Pages/OurFirmOverview.aspx).

[55] Financial Review, July 27, 2012. Lowered sights, new normal. Available: www.afr.com/p/markets/market_wrap/lowered_sights_new_normal_Kpgqxw6TNO4JeeuPFUrScP

taxes) in a swap for their own assets, the range of responses was 0.5%-4%.[56]

- Reuters says, "The demand for excessive returns is problematic in several ways. It is psychologically fantastic: if investors really demanded such returns, they wouldn't be gobbling up government debt with much lower yields. It is economically unrealistic: the value of real and financial investments cannot increase at a much faster rate than the 4-5 percent current growth rate of nominal GDP."[57]

- In May 2013, Warren Buffet said investors in U.S. stocks should expect a return of about 6 to 7 percent a year and people who are looking for double those gains are "dreaming." Buffett used the following logic to arrive at his conclusion: The economy, as measured by gross domestic product (GDP), can be expected to grow at an annual rate of about 3 percent over the long term, and inflation of 2 percent would push nominal GDP growth to 5 percent, and stocks will probably rise at about that rate and dividend payments will boost total returns to 6 percent to 7 percent.[58]

- In September 2016, *The Economist* presented the idea that the low interest-rate and growth environment is a long-term trend that may hold despite the efforts of central bank to effect higher interest rates.

[56] The Wall Street Journal, The Intelligent Investor. January 10, 2010. "Why Many Investors Keep Fooling Themselves." Available: online.wsj.com/article/SB20001424052748704381604575005291706758502.html

[57] Reuters Breakingviews, May 29, 2012. "Hurdle rates need post-crisis rethink." Available: www.ldc.investmentview.wallst.com/thomson/component/firm/investmentview/view.asp?uid=markets/latestHeadlines&returnToSection=latestHeadlines&returnToView=headlines&view=newsStory&docKey=315-L4E8GT65L-1&firstRow=640&rowCountSidebar=10&searchType=keyword&keyword=&endDateMS=41058&startDateMS=41057.75&showSearchInputs=false&mode=markets .

[58] Bloomberg, May 3, 2013. "Stock Investors Should Expect 6%-7% Annual Return, Buffett Says." Available: www.bloomberg.com/apps/news?pid=newsarchive&sid=a1.neDMy8DEU. While this article does not have a year associated with it, it is referenced in a Christian Science Monitor article ("What Warren Buffett's stock market math means for your retirement", www.csmonitor.com/Business/The-Simple-Dollar/2013/0506/What-Warren-Buffett-s-stock-market-math-means-for-your-retirement), dated May 6, 2013,

In particular, The Economist article identifies a shift since the 1980s that is supply of savings worldwide has increased as demand for funds to invest has declined.[59] The article offers two primary drivers of the ongoing glut of savings. First, the population is aging, but the length of an average working life has not changed much, indicating a longer retirement and the ancillary requirement that more retirement funds be produced—thus higher savings rates. Second, China's population has a 40-percent savings rate, which cannot be entirely served by its domestic economy and leads savings being sent abroad.[60] There are several more drivers of secular decline in real interest rates. For more information, please refer to the full article, which is attached in Exhibit WM-2. Expectations of inflation and efforts to combat inflation could increase nominal interest rates, while leaving real interest rates relatively low over the longer term than they would have been a decade earlier.

The above review of results and commentary from investment professionals indicates that the ROEs that the Commission sets in this case should be on the lower end of, if not lower than, the utilities' estimates of "reasonable" ROE ranges.

Q. What information has been developed in recent academic literature that relates to the rate of return?

A. The academic literature has provided a significant focus on the risk premium.

[59] The Economist, September 24, 2016. "The fall in interest rates, Low Pressure." P. 2. Available: tinyurl.com/j7pmvfw .
[60] *Id.*, pp. 4-5.

Arnott, elaborating on his work with Bernstein,[61] shows that median excess returns of stocks over bonds measured at 10- and 20-year rolling intervals was 2.4% and 2.7%, respectively, between the years, 1802 and 2010. This leads Arnott to conclude in 2011 that, over the next 10-20 years, risk premium estimates of between 2% and 3% would otherwise be reasonable based on history, but that a risk premium estimate of closer to 1% would be more reasonable, considering "today's low starting yields, the prospective challenges from our addiction to debt-financed consumption, and headwinds from demographics."[62]

Cornell[63] cites limits on future GDP growth, which, in light of "ongoing earnings-per-share dilutions…implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4 to 5 percent in real terms." Of course, utilities should expect less than this because of their low-risk nature relative to the wider universe of companies.

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[61] Arnott and Bernstein's 2002 paper (Robert D. Arnott and Peter L. Bernstein, "What Risk Premium Is 'Normal'?" *Financial Analysts Journal*, Vol. 58, No. 2 64-85 (March-April 2002)), specifically states that "observed" excess returns to stocks and the "prospective" or expected risk premium are two different concepts and that the Ibbotson method of looking at historical data does not provide a risk premium. Their paper suggests that stock prices increase in real terms approximately equally to the real per capita GDP growth over the long term. Many utility cost-of-capital witnesses use Ibbotson (a Morningstar company) estimates of the risk premium. Dr. Hevert used Ibbotson as a check on his "risk premium" method as recently as February, 2009 (APSC Docket No. 09-008-U, starting on p. 41 of Dr. Hevert's direct testimony in that case), although he does not do so in the instant case. As I noted in response to Dr. Hevert's use of Ibbotson in that case, the Ibbotson suffers from the use of returns data from all the way back to 1926, which asks investors to give significant weigh to a recurrence of the economic conditions of 60-80 years ago (the Great Depression, World War II, and Federal Reserve Board monetary policy designed to keep interest rates down for the purpose of financing government war debt cheaply). There is much evidence, as illustrated in this testimony, to show that the Ibbotson view of the world is not relevant today. Results that appear to conform to Ibbotson, even if they are not explicitly compared to Ibbotson, should be discounted as unreasonably high, therefore.

[62] Arnott, Robert. "Equity Risk Premium Myths." Published in The Research Foundation of CFA Institute's *Rethinking the Equity Risk Premium*, December 23, 2011, p. 78. Available: www.cfapubs.org/doi/pdf/10.2469/rf.v2011.n4.full.

[63] Cornell, Bradford. "Economic Growth and Equity Investing," *Financial Analysis Journal* (January/February 2010). Emphasis added.

Donaldson, Kamstra, and Kramer[64] claim that it is simplistic to estimate the *ex ante* risk premium expected by investors solely using historical data on *ex post* returns without considering other aspects of the data related to market returns.[65] This information specifically includes dividend yields, Sharpe ratios,[66] and return volatility. When all of this information is used to simulate the performance of the US markets over the past 50 years, these authors compute an *ex ante* risk premium of 3.5%. This is a very different result from the 10.68% that Mr. Hevert obtains with his *ex ante* approach to CAPM.

E. Dimson, P.R. Marsh, and M. Staunton,[67] in an article that focuses on how big the equity risk premium has been, historically, and what risk premium investors, corporate managers, and regulators can expect going forward conclude:

> [I]nvestors expect a long-run equity premium (relative to bills) of around 3-3.5 percent on a geometric mean basis and, by implication, an arithmetic mean premium for the World index of approximately 4.5-5 percent. From a long-term historical and global perspective, the equity premium is smaller than was once thought.

Even J. Siegel of Wharton Business School at the University of Pennsylvania, who claims to be upbeat about stock performance over

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[64] Donaldson, Glen, Kamstra, Mark J. and Kramer, Lisa A., "Estimating the Equity Premium" (November 2008). Rotman School of Management Working Paper Available at SSRN: ssrn.com/abstract=945192

[65] *Ex ante* risk premiums are risk premiums that investors would experience at the time they were making investment decisions, whereas *ex post* risk premiums are those risk premiums that were observed based on the market results after the fact.

[66] The Sharpe ratio measures the riskiness of a portfolio based on the portfolio return minus the risk free rate divided by the standard deviation of portfolio returns.

[67] E. Dimson, P.R. Marsh, M. Staunton, "Equity Premiums around the World". Published in The Research Foundation of CFA Institute's *Rethinking the Equity Risk Premium*, December 23, 2011 at p. 51. Available: www.cfapubs.org/doi/pdf/10.2469/rf.v2011.n4.full.

the coming 10 years, states that he expects stocks to outperform bonds by 5-6%, despite his rosy outlook regarding stocks.[68]

Finally, we turn to papers that involve survey results. Ivo Welch's 2007 "Welch Survey" (published in 2008)[69] is a survey of 400 finance professors. It indicates a one-year equity premium and a 30-year geometrically-averaged equity premium of about 5%. Participants in the Welch Survey estimate a 30-year arithmetic equity premium at about 75 basis points above the geometric equivalent, and they estimate that the 30-year geometric expected rate of return on the stock market at about 9%. While higher than some of the other estimates, the arithmetic mean of risk premium responses was still 5.75%, which is well below a back-to-1926 average figure of 7.60% and the 10.61% figure that Mr. Hevert suggests. Dr. Welch updated his survey in January 2009, which was at the height of the financial crisis, and found expected equity risk premia of between 5% and 6%.[70]

More recently, P. Fernandez, J. Aguirreamalloa, and L Corres did a similar survey to the Welch Survey in 2016. Of 2,536 respondents, consisting of finance and economics professors, analysts, and investment managers, the average and median response to the question of what is the market risk premium was 5.3% and 5.0%, respectively.[71] In fact, respondents to the survey responded with average *total* market returns of 7.9%.

[68] J. Siegel, "Long-Term Stock Returns Unshaken by Bear Markets." Published in The Research Foundation of CFA Institute's *Rethinking the Equity Risk Premium*, December 23, 2011 at p. 147. Available: www.cfapubs.org/doi/pdf/10.2469/rf.v2011.n4.full.

[69] Welch, Ivo, "The Consensus Estimate for the Equity Premium by Academic Financial Economists in December 2007" (January 2008). Available at SSRN: papers.ssrn.com/sol3/papers.cfm?abstract_id=1084918

[70] Welch, Ivo, "Views of Financial Economists On The Equity Premium And Other Issues," The Journal of Business 73-4, October 2000, 501-537, with 2009 update. Results available: research.ivo-welch.info/equpdate-results2009.html.

[71] P. Fernandez, J. Aguirreamalloa, and L Corres, "Market Risk Premium used in 71 countries in 2016: a survey with 6,932 answers," April 23, 2015 (p. 3). IESE Business School – University of Navarra.

Harvey and Graham have conducted extensive empirical studies of the equity risk premium, by interviewing CFOs of large companies and asking them what they expect as a risk premium. They have found a 10-year equity risk premium (relative to 10-year treasury bonds) declining from about 4.5% in 2000 to an average of 3.4% during the period prior to the crisis (January 2007 through September 2008).[72] While the risk premium sharply increased to 4.56% during the financial crisis peaking in February 2009, the premium declined to 3.73% (mean) or 3.30% (median) by March 2014.[73] It has since risen to 4.02% (mean) or 3.19% (median) in the second quarter of 2016.[74] Moreover, CFOs in 2016 gave the market only a one-in-ten change of returning at least 9.71%.[75] The average risk premium from 2002 to 2016 was 3.61%.[76] Even with a conservatively high, risk-free 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 2.42%)[77] indicates an average market return of about 8%. This is much lower than the expectations suggested by OG&E in this case. Exhibit WM-3 contains the most recent, 2016 version of this semi-periodical paper.

These academic results indicate risk premiums that are clearly less than could support OG&E's ROE request of 10.25%.

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[72] Graham, John R. and Harvey, Campbell R, "The Equity Risk Premium Amid a Global Financial Crisis" (August 9, 2010). Available at SSRN: ssrn.com/abstract=1654026

[73] *Id.* "The Equity Risk Premium in 2016" (June 25, 2015), p. 8 Available: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2611793.

[74] *Id.*

[75] *Id.*

[76] *Id.*

[77] US Treasury, as of January 6, 2017. Accessed: www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield.

Q. Have any stock analysts recently presented information regarding the market risk premium?

A. Yes. Duff and Phelps[78] published its most recent market return on March 16, 2016, with instructions to use it until further notice. The financial advisory and investment-banking-services company recommends to its clients that they assume a market return of 9.5% (composed of a risk-free rate of 4% and a market risk premium of 5.5%). With a Value Line Beta value of 0.74,[79] these values indicate an equity return of 8.07%—*i.e.*, 4.0% + (0.74 X 5.5%) with CAPM. This document is included as Exhibit WM-4. It should be noted that this is a longer term rate, with a higher risk-free rate than is observed in the current market, although close to the Blue Chip estimate referenced by Mr. Hevert.

Q. Have any stock analysts presented information that is relevant to the application of the Discounted Cash Flow model for calculating equity returns for utilities?

A. Merrill Lynch in a report, titled, "Electric Utilities and Competitive Power,"[80] in December, 2009 made the following comment:

> With an average yield of 4.6% and projected 3.4% dividend growth, traditional regulated utility stocks provide a favorable tax-advantaged income alternative, particularly relative to the shrinking yields on utility bonds.

A number of salient points can be made from this information. First, given a DCF "yield plus growth" model, the quote implies that

[78] Duff & Phelps, March 16, 2016. "Client Alert: Duff & Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016". Duff & Phelps is a global financial advisory and investment banking firm that advises clients in the areas of valuation, M&A and transactions, restructuring, alternative assets, disputes and taxation.

[79] Average of the Value Line Betas of Dr. Hevert's comparison group of companies, as of January 5, 2017.

[80] Merrill Lynch. December 16, 2009. "Electric Utilities and Competitive Power, Attractive for income, but commodity headaches," p. 1.

traditional regulated utilities are producing a cost of equity on the order of 8% (4.6% average yield plus a projected 3.4% dividend growth) on market value. Secondly, this quote indicates that such a return should be viewed as favorable by investors. In comparison, Mr. Hevert was recommending ROEs on the order of 11.25% in 2009.[81]

2. Historical Comparison of Utility and Broad Market Returns

Q. Have you prepared any comparisons of historical stock market returns, returns on utility stocks, and bond returns over a long period of time (*i.e.*, a period of time that could be used in a historical CAPM)?

A. Yes. I have prepared a comparison of returns for electric utilities, gas utilities, the S&P 500 and bonds (using electric and gas utility return and bond return data presented by Dr. Roger Morin)[82] and S&P 500 data developed by Dr. James Vander Weil, a utility witness in a Pacific Gas & Electric Company cost of capital case, shown in Table 6 below.

I used the period 1955-2001. I purposely chose the beginning of the period to start after the end of the Korean War and the ensuing 1954 recession, as well as after the beginning of "modern monetary policy." The period of time that includes the Great Depression and World War II and its aftermath does <u>not</u> reflect conditions that current investors believe hold today or are likely to recur in the future, even though reaching farther back in history produces higher risk premium numbers that utility rate of return analysts like to use. The end of the

[81] *See, e.g.*, Colorado Utilities Commission Docket No. 09AL-507G, Direct Testimony of Robert B. Hevert, p. 2 (lines 24-25).
[82] Electric utility and bond return from Exhibit RAM-3 of his testimony in APSC Docket No. 06-101-U (Entergy Arkansas, Inc. General Rate Case), available: http://www.apscservices.info/PDF/06/06-101-u_16_1.pdf; gas utility return from Exhibit RAM-3 of APSC Docket No. 04-176-U (Arkansas Western Gas Company rate case), available: http://www.apscservices.info/efilings/Docket_Search_Documents.asp?Docket=04%2D176%2DU&DocNumVal=9.

period (2001) was the last year for which Dr. Morin presented data in AWG's 2004 rate case (Docket No. 04-176-U).

Table 6: Returns and Risk Premiums for Electric Utilities, Gas Utilities, the S&P 500, and Long-Term Treasury Bonds

	1955-2001	1960-2001	1967-2001	1983-2001	1955-1966	1967-1982
S&P 500 return	11.86%	11.77%	12.31%	15.33%	10.57%	8.73%
Electric Utility Return	11.53%	11.47%	11.53%	15.30%	11.52%	7.05%
Gas Utility return	12.16%	11.79%	12.25%	15.07%	11.91%	8.91%
Bond Return	6.33%	7.27%	7.90%	11.17%	1.73%	4.02%
Electric Utility risk premium	5.20%	4.20%	3.62%	4.13%	9.79%	3.03%
Gas Utility risk premium	5.84%	4.52%	4.35%	3.89%	10.18%	4.89%
S&P 500 risk premium	5.54%	4.51%	4.41%	4.15%	8.84%	4.71%
Electric utility return as % of S&P 500	97.1%	97.4%	93.6%	99.8%	109.0%	80.8%
Gas utility return as % of S&P 500	102.5%	100.1%	99.5%	98.3%	112.7%	102.1%

Over the 46 years from 1955-2001, the S&P 500 had a return that averaged 5.54% above long-term treasury bonds. This is approximately 56 basis points below the arithmetically-derived risk premium of corporate stocks against long-term corporate bonds.

Q. Will you compare the returns on utility stocks versus the S&P 500 in the table above?

A. The rest of this chart is even more interesting than the risk premium estimate. Over the 46 years ending in 2001, electric utilities underperformed the S&P 500 by only 33 basis points (2.9%) despite being considerably less risky (with betas[83] less than 1). Over sub-periods, the return ranged from 81% to 109% of the S&P 500. The lowest return was experienced in the 1967-1982 period, a time when electric utilities in particular faced depressed prices due to the lack of fuel adjustment clauses in the 1974 oil shock coupled with dramatic reductions in demand growth, massive capital spending programs, and

[83] Beta, as used in this context, beta is a measure of market risk exposure in a given stock as compared to the broader market. A beta less than one indicates that a stock is less risky than the broader market and expected to produce less return than the broader market.

burgeoning interest rates. In the 1983-2001 period, electric utilities provided a return virtually identical to the S&P 500.

Gas utilities had even better performance. Gas utilities <u>outperformed</u> the S&P 500 by 30 basis points (2.5%) despite being less risky (with betas less than 1 over the vast portion of the historical period). Over sub-periods, the return ranged from 98% to 113% of the S&P 500 – a return virtually identical to the market as a whole.

This finding needs to be compared with a principle cited in key court cases on rate of return—that the authorized return on common equity should be the same as returns on investments in other firms with similar risks. When a group of less-risky, low-beta regulated utility stocks performs as well as the market as whole this risk principle has clearly been violated. This suggests that there has been some kind of long term "free lunch" for utility investors, which the market may not yet have fully recognized. The "free lunch" may arise from the circular nature of the setting of utility returns – high returns in the past beget requests by utilities for high returns in the future,[84] which in turn begets stock performance equal to the S&P 500 over the long run with considerably less risk (particularly in the past) than the S&P 500.

Q. Have you been able to update this information beyond 2001?

A. The last datum in this particular series is from 2001. However, other information comparing the electric and gas utility sub-indices of the S&P 500 and the S&P 500 in the US has recently been developed by Professors Lawrence Kryzanowski and Gordon Roberts for 1989-

[84] A prime example of such circularity is Dr. Hevert's use of authorized returns by other state Commission to derive his recommended risk premium.

2008.[85] These data indicate that utilities have outperformed the S&P 500 over this 20 year period as well as the last decade (where utility performance has been positive and S&P 500 performance has been negative).

In addition, in the last fifteen years, the utility Exchange Traded Fund (Utilities Sector Spider Fund - XLU) had performance that exceeded the S&P 500 in eight of the 14 years. Furthermore, from 2002 to 2016, XLU <u>outperformed</u> the S&P 500 by <u>14%</u> – *i.e.*, the S&P 500 gained 266% in that time period, XLU gained 298%. The data are indicative of the utility investor "free lunch", given that the XLU has outperformed the S&P 500 despite being composed of companies whose betas are smaller and are thus less risky than the market as a whole, shown in the following figures.

[85] Lawrence Kryzanowski and Gordon Roberts, Prepared Testimony on behalf of the Office of the Utilities Consumer Advocate in Alberta Utilities Commission Docket 1578571/Proceeding No. 85 (March 2, 2009), pp. 288-289 and Schedules 5.3 and 5.4 (pages 412-413).

Figure 1: Returns of Utility Index vs. S&P 500

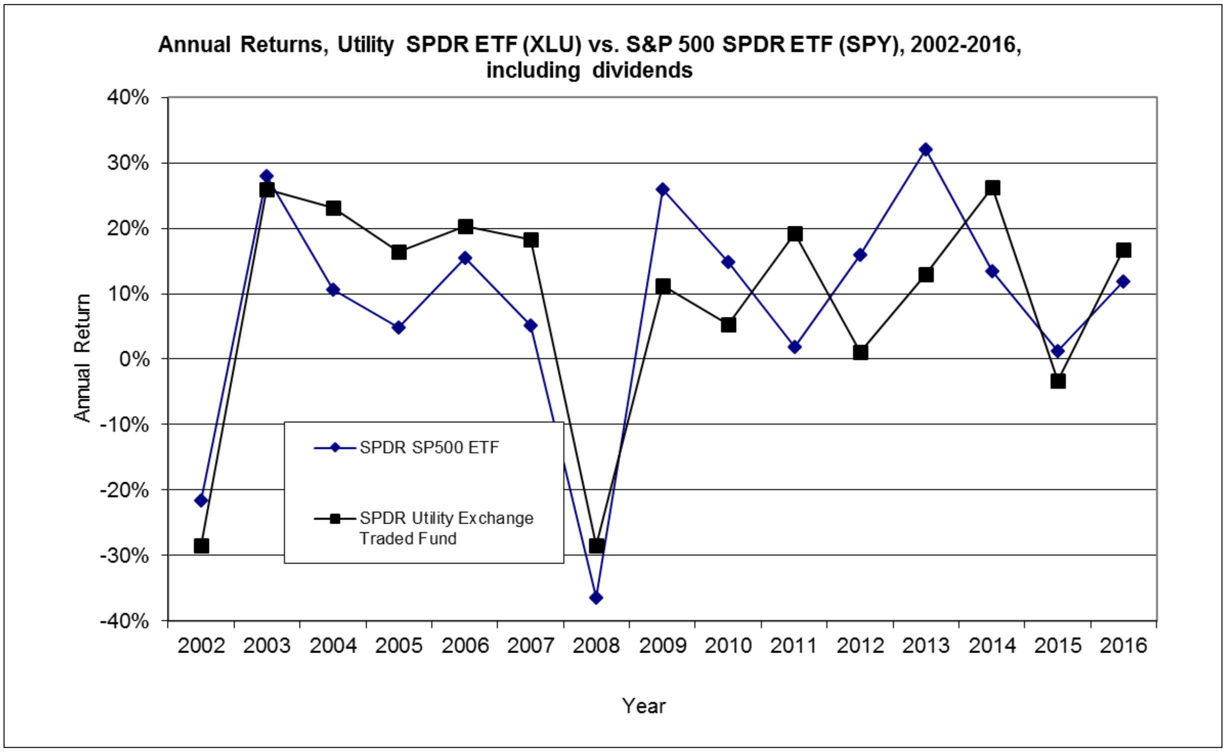
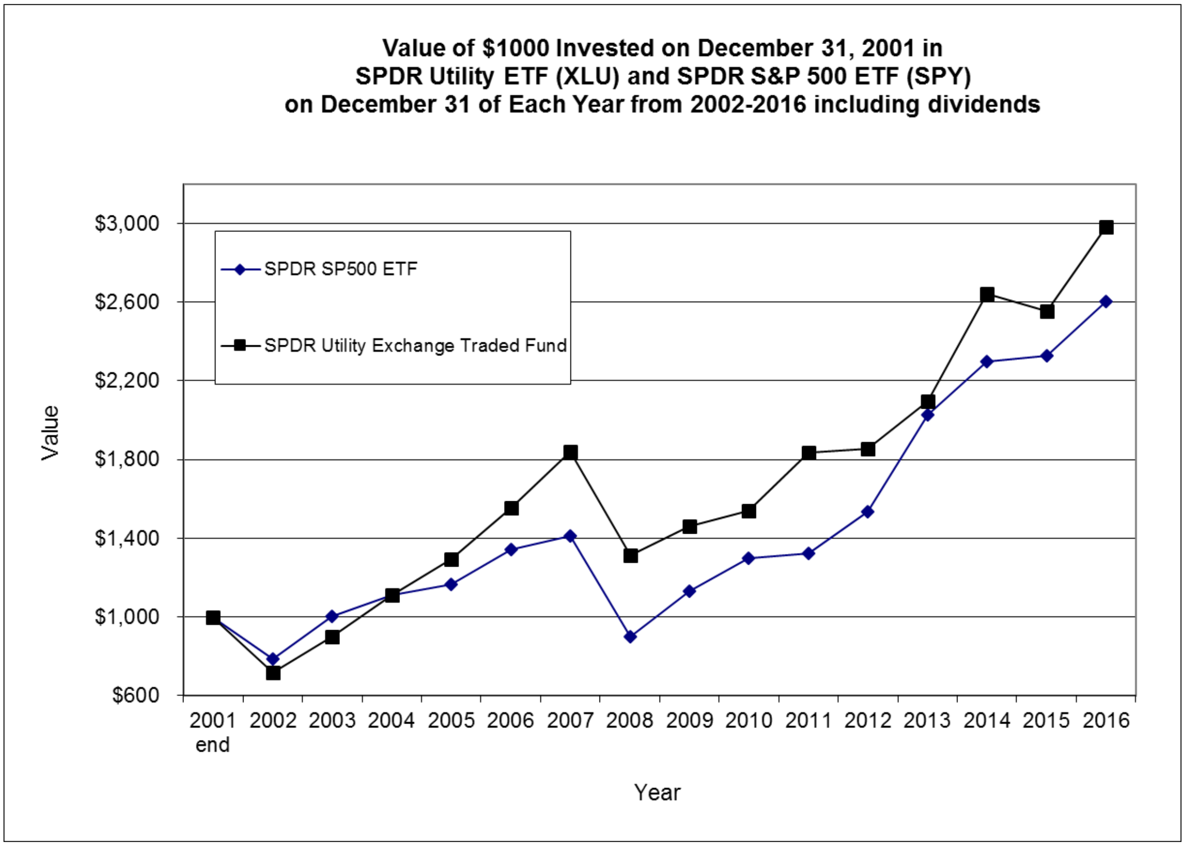


Figure 2: Value of Utility Index vs. S&P 500



It is further interesting to note that utilities far outperformed all other sectors in the 1988-1997, the most recent 10-year period depicted in the Mario Levis piece that Mr. Hevert used to support the notion of a small-size premium in his SourceGas Arkansas testimony last year.[86]

If one were to see such outperformance over a long period of time, it would make one wonder whether utilities were obtaining some sort of free lunch through the regulatory process, itself, given that as Mr. Hevert freely admits utilities are less risky than the market as a whole and should therefore return less not more than the overall market.

Q. What do you conclude from these data?

A. The trends from the data above clearly indicate that utility investors have been receiving a "free lunch" for significant portions of the past.

[86] Docket No. 15-011-U. Direct Testimony of Mr. Hevert, p. 42 (Footnote 29).

Furthermore, with respect to analysts' growth forecasts – a key input of the DCF method - the issue of circularity is also evident. Academic analyses have suggested that stock market analysts' forecasts are biased to the high side as a general matter.[87] In particular, we note that ValueLine, one of Mr. Hevert's sources, makes relatively optimistic forecasts of economic growth 3-5 years in the future as a means of comparing stocks using a common economic environment, without the complications of trying to predict bumps in the road of economic growth.[88] In the utility industry, analysts consider the size of past ROE decisions when making their predictions of future growth. To the extent that high authorizations in the past have contributed to high actual returns in the past, and that analysts use those high authorizations to inform their view of the future, their growth expectations will systematically produce unreasonably-high growth estimates merely because past returns have been unreasonably high. Finally, to the extent that commissions rely on methods that rely on growth projections, such as the DCF model, that make use of projections that are influenced by the expectation of continued unreasonably-high ROE authorizations, which could explain why the cycle of excessively high ROE authorizations has continued for so long.

The Commission should be cognizant of this free-lunch phenomenon as it analyzes the data presented by Mr. Hevert in this case.

Q. Are you providing any additional quantitative information as a check on the information presented by Mr. Hevert?

A. Yes. Table 7 depicts CAPM calculations over a range of market return assumptions, using several different risk-free rates – both current and

[87] Andrew Edwards, "Study Suggests Bias in Analysts' Rosy Forecasts," Wall Street Journal, March 21, 2008, page C6, citing studies by J. Randall Woolridge, a finance professor at Pennsylvania State University.

[88] For example, See Value Line Investment Survey, Issue 11, August 6, 2010, p. 2100.

hypothetical – and the most recent average Value Line beta (0.74[89]) for Mr. Hevert's proxy companies.

[89] Average of proxy company betas, as reported by Value Line on January 5, 2017. The use of Value Line's figures at this time does not represent an endorsement of those figures as a general proposition.

1 Table 7: Range of Capital Asset Pricing Method Results

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Item	Lower-End Risk Premium (current RF[1])	Mid-Point Risk Premium (current RF[1])	Upper-End Risk Premium (current RF[1])	Upper-End Risk Premium (proj'd (2018) RF[2])	Upper-End Risk Premium (elevated RF[3])	Hevert Implied Risk Premium[4] (current RF[1])	Duff and Phelps Equity Return Analysis[5]
Risk-free rate	3.11%	3.11%	3.11%	3.90%	5.00%	3.11%	4.00%
Market equity return	7.11%	7.86%	8.61%	9.40%	10.50%	14.46%	9.50%
Risk premium	4.00%	4.75%	5.50%	5.50%	5.50%	11.35%	5.50%
Beta[6]	0.74	0.74	0.74	0.74	0.74	0.74	0.74
ROE for regulated utility using CAPM	6.07%	6.62%	7.18%	7.97%	9.07%	11.51%	8.07%

[1] 30-year Treasury Bond rate, average from 12/5/16 through 1/4//17 (US Federal Reserve, accessed 1/5/17): http://www.federalreserve.gov/datadownload/Output.aspx?rel=H15&series=b56abb6d9cc35f28ccf86b8a0188e948&lastObs=&from=&to=&filetype=csv&label=include&layout=seriescolumn

[2] 30-year Treasury Bond rate forecast, as reported in Blue Chip Financial Forecasts (in Vol. 35, No. 7, July 1, 2016, at 2) and refenced by Mr. Hevert in Direct Exhibit RBH-5)

[3] 30-year Treasury Bond Rate forecast, conservatively-high assumption.

[4] Using the Value Line-derived implied MRP. The Bloomberg-derived MRP is 10.68%.

[5] The Duff & Pehlps risk-free rate is based on a normalied 20-year bond

3 [6] Average beta (per estimates from Value Line, as of 1/5/17) for Mr. Hevert's 16 comparison utilities.

The Lower-, Mid-Point-, and Upper-End risk MRPs are the types of MRPs suggested by the academic and professional sources surveyed in this testimony. As the results in the table show, realistic market-return assumptions along with the current risk-free rate and the average Value Line Beta yield a CAPM-generated ROE range of between 6.07% and 7.18%. Mr. Hevert's Value Line-based implied MRP of 11.35% yields a regulated ROE of 11.51% (using Value Line's betas for proxy companies); Market returns of 14.46% with a corresponding risk premium of 11.35% is unsustainable over the long term because such a risk premium is considerably higher than the mean over time (which according to Ibbotson is about 7.6% - see Footnote 61). Moreover, the Ibbotson MRP (*i.e.*, 7.6%) that Mr. Hevert used before the financial crisis yields a return of 8.73%,[90] or 152 basis points below Mr. Hevert's point estimate in this case.

3. Critique of Mr. Hevert's Methods

a. DCF

Q. Please comment on Mr. Hevert's DCF presentation.

A. I repeat that Mr. Hevert's use of "Mean Low" and "Mean High" DCF results only serve to bias the witness's results high. While the Mean Low results nominally balance the Mean High results, the implication of the rest of Mr. Hevert's testimony is that the Commission should ignore the Mean Low results and adopt estimates that are closer to the Mean High results. The Commission should ignore this attempt to change the optics of the results.

I add that Mr. Hevert ignores the time frame of the rate-effective period when he disavows the constant-growth DCF model. We have

[90] Using today's 30-year Treasuries and Value Line's beta, combined with the Ibbotson MRP.

included higher inflation rates in our CAPM model to give the Commission more information, but the Commission is not forecasting rates in effect beyond the pro forma year. A utility could theoretically file a rate case if something significant changes. Therefore, Mr. Hevert's concerns about the Constant Growth DCF application, which are about 20 basis points lower on average than those the witness obtains with the Multi-Stage Growth DCF,[91] are diminished, once one adjusts the DCF for today's information.

b. CAPM

Q. How does Mr. Hevert calculate the market risk premium?

A. Mr. Hevert subtracts the current and forecasted 30-year Treasury bond yield from his calculation of the expected return on the S&P 500 Index, to which he applied a constant-growth DCF model, which results in an "implied market risk-premium" estimate of 10.68% and 11.35% using Bloomberg and Vanguard, respectively.

Q. Please comment on Mr. Hevert's CAPM methodology.

A. It should be understood without any explanation that risk premiums in the range of 10.68% and 11.35 are unreasonable on their face. Mr. Hevert's application of CAPM suffers from several infirmities, which serve to overstate what a reasonable result would be.

First, as noted above, the ValueLine results are based on a common set of relatively optimistic economic conditions. If those conditions do not occur, then ValueLine's growth forecast will not be realized. Mr. Hevert is assuming that there is 100% probability that the economy

[91] Compare Mr. Hevert's Constant Growth DCF (Exhibit RBH-1) with the Multi-State Mean 30 Day DCF (Exhibit RBH-2). These use all the same information except that the second is multi-stage.

will run smoothly over the next several years – and out into the distant future. No sophisticated investor would make such a plan.

Mr. Hevert subtracts the 30-day average of actual, *current* risk-free instrument yields from his calculation of average growth forecasts, which are based on long-range growth projections, to arrive at an inflated risk premium. The witness then adds that risk premium—again, based on current risk-free yields and DCF results based on long-term growth rates—to a *forecasted* risk-free yield to get a return on equity that he considers germane to utilities (after multiplying by the comparison-group, average beta). The Commission recognized, however, in the last Entergy general rate case (GRC) that it must make ROE decisions based on present facts, not the anticipation of increasing rates.

Second, Mr. Hevert's reliance on *ex ante* information to run his CAPM circumvents the conventional use of the CAPM, which is to provide a check on the conventionally *ex ante*, DCF method. Mr. Hevert has and Staff will run several incarnations of DCF method; it makes little sense to use it again by dressing it up in CAPM clothing, especially when it produces risk premia that are so clearly out of step with reality.

Q. Is Mr. Hevert consistent in his application of his CAPM method?

A. No. For example, in 2008 Mr. Hevert used the *ex post* methodology and data to support his application of CAPM. At some point, presumably after the economic crisis, when the risk free rate fell, Mr. Hevert changed his method and began using this *ex ante* approach which achieved higher results. As late as 2013, the witness justified the use of such tactics by indicating the following about *ex post* applications of CAPM:

> [The CAPM has been affected by recent economic conditions.] For example, the risk-free rate, "rf," is represented by the yield on long-term U.S. Treasury securities. During periods of increased equity market volatility, investors tend to allocate their capital to low-risk securities such as Treasury bonds, thereby bidding down the yield on those securities. In addition, since the 2008 Lehman Brothers bankruptcy filing, the Federal Reserve has focused on maintaining low long-term interest rates. However, the capital markets continue to change, by some measures quite significantly. For example, over the 90 trading days ended October 18, 2013 the 30-year Treasury yield ranged from a low of 3.28 percent to a high of 3.90 percent. In addition (and as discussed later in my Direct Testimony), the Equity Risk Premium is not constant, and tends to move in the opposite direction as changes in interest rates. Consequently, the CAPM results can be relatively volatile.[92]

At some point, Mr. Hevert dropped this language (*e.g.*, as recently as his January 2015 testimony Ameren's GRC before the Illinois Commerce Commission[93]), but the preceding quotation is relevant to this case because this commission has specifically said in the past that analysts should not ignore current Treasury rates in favor of higher return estimates.

If Mr. Hevert had used the typical Ibbotson/Morningstar-derived risk premium of 7.6%[94] his comparison companies would have returned an

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[92] New Jersey Board of Public Utilities Docket No. ER13111135 (Rockland Electric Company rate case). Direct Testimony and Exhibits of Robert B. Hevert (November 27, 2013), pp. 22 (starting at line 13) – 23.

[93] See Mr. Hevert's Direct Testimony in Docket No. 15-0142.

[94] Ibbotson/Morningstar generates a risk premium based on historical data that dates back to 1926, which has been about 7.6%. As noted above, this estimate of the risk premium is inflated because places undue weight on the unreasonable effects of such events as the Great

average ROE of 7.97% using his estimate of current Treasury yields and 8.62% using his near-term projection of Treasury yields.[95] If the witness had used the more reasonable estimate of the risk premium of 5.5% his result would have been further reduced, still, to 8.02% when using a forecasted risk-free rate of 4%.[96]

c. Bond Yield plus Risk Premium

Q. What is your evaluation of Mr. Hevert's risk premium method?

A. The most important issue is that Mr. Hevert uses authorized returns from other state Commissions as a proxy for returns that the market might "expect," which is both circular and requires the Commission to abdicate its responsibility. His regression equation is also suspect because it relies on regulatory commission actions relative to Treasury bond yields when state commissions are relatively slow and conservative in both directions. Seven years after the financial crisis, in a period of continued historically low interest rates, I would suggest that the APSC should continue to recognize low interest rates as it has in the past and remain above the purely descriptive, circularly-constructed material presented by Mr. Hevert in this case.

Q. Will you summarize your position regarding the rate of return on common equity?

A. The requested 10.25% return on equity for a utility like OG&E is simply not reasonable under the circumstances.

Depression, World War II and Federal Reserve Board monetary policy designed to keep interest rates down for the purpose of financing government war debt cheaply. Mr. Hevert used 7.6% in his Minnesota Ameren testimony (p. 7 of Mr. Hevert's Direct Testimony (September 17, 2004) in Docket No. G002/GR-04-1511).

[95] This is assuming Mr. Hevert's 30-day average of 30-year bond yields (2.35% current and 3.00% near-term projection) and comparison-company betas.

[96] This calculation uses the Duff and Phelps estimate of the risk premium (5.5%) and risk-free rate (4%), as shown in Table 7, and Mr. Hevert's ValueLine-derived estimate of Beta (0.73).

1. OG&E's own constant growth DCF results range between 8.35% and 9.10%. Its multi-stage growth rates assume higher economic growth or higher inflation than is likely to occur (5.27% GDP growth), but even they are in the range of 8.9% to 9.4%. The company has given no reasonably justification for adjusting its results above the upper end of that range, let alone to the 10.25% range.

2. The average equity return expected by the pension actuaries of the utilities identified by Mr. Hevert as a comparison group to OG&E is 8.91%, given an average discount rate (high grade long-term corporate bond rate) of 4.23%. The utility return would be lower than 8.91%.

3. The average expected return from 2002 to 2015 for the entire market was around 7.3% (risk premium of 3.6%) from Graham and Harvey's CFO survey.

4. Other academic literature, as well as the analysis by the Russell Investment Group suggests a risk premium of 3% to 5%, which corresponds to an overall stock market return below 10%, placing utilities below 9%.

5. Historical data that does not reach back to the Depression and World War II or manufacture *ex ante* risk premia supports equity returns of 9.3% or less.

6. The fact that utilities have earned more than the S&P 500 index for decades despite utilities' lower risk and lower beta than that index.

7. Research by Duff and Phelps, which suggests that returns on the entire market are expected to be 9%, which means returns on utilities should be expected to be lower than 9%.

A reasonable interpretation of CAPM results today would be to focus on the top reasonable end of the range at this time (6.6% to 7.9%) and to add 50-100 basis points. This adder would address the potential that the risk-free rate is relatively low and reflect the need for additional financial flexibility, yielding a range of 7.6% to 8.9%. If relying on the CAPM together with judgment about future financial conditions and considerations of regulatory continuity, my recommendation would be slightly below 9%.

However, I recognize that the Arkansas PSC typically relies on DCF analysis, and my work is a complement to it. This information should point this Commission directionally lower than the midpoint of the Staff DCF range, given its traditional reliance on the DCF. With the type of analysis prepared by Staff in normal cases and the fact that even Mr. Hevert's forecast of treasury bond rates is 70 basis points lower than OG&E's last rate case, I would recommend setting OG&E's ROE at 9.3% without a formula rate plan and at 9.05% with the formula rate plan because of the significant reduction of risk and regulatory lag that it would provide. I may update this recommendation depending upon the Staff's final DCF analysis.

Q. Will you briefly comment further on the impact of the FRP on the rate of return?

A. The FRP is qualitatively very different from other mechanisms for weather normalization, decoupling, or riders for specific programs. It reduces the risk of **EVERYTHING on the utility system** by allowing the utility to raise rates if there is a small deficiency in its equity return. The utility faces limited risk from sales and customer losses, limited risk from increases in operations and maintenance expenses, whether on safety and reliability or head office corporate overhead, and limited risk if its capital expenses increase, either because it chooses to do more work or if it does not control costs. In essence, the business risks of the utility are dramatically limited with FRP, while other ratemaking methods only reduce certain aspects of risk.

C. *Recommendations on Rate of Return*

Q. Have you prepared a summary showing your proposed rate of return on rate base?

A. I recommend a rate of return of 5.30% (7.44%, pre-tax), compared to OG&E's update of 5.97% (8.60% pre-tax) assuming that FRP is adopted, as it has been for two other utilities. Details are shown in the table below.

Table 8: Attorney General's Recommended Rate of Return without FRP

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)
		Amount		Amount					
		Beginning of Pro	Pro Forma	End of	Proportion			Weighted Cost %	Pre-Tax
Line No.	Description	Forma Year (a)	Adjustments	Pro Forma Year	(Amount/Total)	Rate % (b)		(Col.6 x Col.7)	Weighted Cost %
1	Long Term Debt	$ 2,545,795,630	$ 418,642,718	$ 2,964,438,348	36.02%	5.36%		1.93%	1.93%
2	Common Equity	3,175,571,011	(162,418,480)	3,013,152,531	36.61%	9.30%		3.41%	5.60%
3	Accumulated Deferred Income Taxes	2,112,951,717	(398,866,239)	1,714,085,478	20.83%	0.00%		0.00%	0.00%
4	Pre-1971 ADITC								
5	Post-1970 ADITC - Long Term Debt	1,072,233	33,107	1,105,340	0.01%	5.36%		0.00%	0.00%
6	Post-1970 ADITC - Short Term Debt	(3,369)	67,337	63,968	0.00%	1.51%		0.00%	0.00%
7	Post-1970 ADITC - Equity	1,337,404	(213,951)	1,123,453	0.01%	9.30%		0.00%	0.00%
8	Customer Deposits	77,441,663	-	77,441,663	0.94%	1.47%		0.01%	0.01%
9	Short Term/Interim Debt	(8,173,166)	179,873,166	171,700,000	2.09%	1.51%		0.03%	0.03%
10	Current, Accrued and Other Liabilities	670,999,789	(394,253,038)	276,746,751	3.36%	0.00%		0.00%	0.00%
11	Other Capital Items	8,909,839	700,361	9,610,200	0.12%	7.38%		0.01%	0.01%
12	Totals	$ 8,585,902,752	$ (356,435,020)	$ 8,229,467,733	100.00%		(A)	5.39%	7.59%

Table 9: Attorney General's Recommended Rate of Return with FRP

		Pro Forma Year as of 06/30/2017							
(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)
Line No.	Description	Amount Beginning of Pro Forma Year (a)	Pro Forma Adjustments	Amount End of Pro Forma Year	Proportion (Amount/Total)	Rate % (b)		Weighted Cost % (Col.6 x Col.7)	Pre-Tax Weighted Cost %
1	Long Term Debt	$ 2,545,795,630	$ 418,642,718	$ 2,964,438,348	36.02%	5.36%		1.93%	1.93%
2	Common Equity	3,175,571,011	(162,418,480)	3,013,152,531	36.61%	9.05%		3.31%	5.45%
3	Accumulated Deferred Income Taxes	2,112,951,717	(398,866,239)	1,714,085,478	20.83%	0.00%		0.00%	0.00%
4	Pre-1971 ADITC								
5	Post-1970 ADITC - Long Term Debt	1,072,233	33,107	1,105,340	0.01%	5.36%		0.00%	0.00%
6	Post-1970 ADITC - Short Term Debt	(3,369)	67,337	63,968	0.00%	1.51%		0.00%	0.00%
7	Post-1970 ADITC - Equity	1,337,404	(213,951)	1,123,453	0.01%	9.05%		0.00%	0.00%
8	Customer Deposits	77,441,663	-	77,441,663	0.94%	1.47%		0.01%	0.01%
9	Short Term/Interim Debt	(8,173,166)	179,873,166	171,700,000	2.09%	1.51%		0.03%	0.03%
10	Current, Accrued and Other Liabilities	670,999,789	(394,253,038)	276,746,751	3.36%	0.00%		0.00%	0.00%
11	Other Capital Items	8,909,839	700,361	9,610,200	0.12%	7.38%		0.01%	0.01%
12	Totals	$ 8,585,902,752	$ (356,435,020)	$ 8,229,467,733	100.00%		(A)	5.30%	7.44%

The Attorney General's recommendations (before FRP) yield a rate of return that is 67 basis points below OG&E's updated figures shown in APSC-12 (116 basis points including income taxes). Table 10 shows the difference in basis points from each of the Attorney General's recommendations taken in the following order.

Table 10: Differences in Recommended Rate of Return (Basis Points)[97]

	Return	Return & tax
OG&E Recommended	5.97%	8.60%
49% Equity, 51% Debt	0.11%	0.31%
Include Short-term debt	0.08%	0.08%
Reduce long-term debt	0.04%	0.04%
ROE 9.3%	0.35%	0.57%
Attorney General without FRP	5.39%	7.59%
ROE 9.05%	0.09%	0.15%
Attorney General with FRP	5.30%	7.44%

Q. What is the approximate impact of your recommendation on OG&E's recommended rate increase?

A. With OG&E's rate base of approximately $543 million, the Attorney General's recommended reduction to the return on rate base with FRP (before any other adjustments) reduces the revenue requirement by about $6.3 million.

Q. What do you recommend for the formula rate plan period?

[97] Note that some of these effects are interactive. The differences shown here reflect the order in which the adjustments are taken on this table.

A. I recommend that my recommended rate of return (including the financial capital structure and the cost of debt and cost of equity) be used throughout the formula rate period. Updates should only be allowed for the changes in the percentage and the Arkansas cost rate on customer deposits, changes in the percentage of current and accrued liabilities, and changes in the percentage of accumulated deferred income taxes.

III. Other Revenue Requirement Issues

A. *Incentive Compensation*

1. General Regulatory Considerations

Q. Why should regulators care about executive compensation in general and stock-based and other incentive compensation in particular?

A. There is a fundamental difference between a competitive unregulated company and a regulated company in the effect of executive compensation on consumers. The literature on executive compensation is related to the "agency" problem; managers have incentives to act in their own best interests, but when running a company they are acting as agents of shareholders.[98] The literature often presents executive compensation issues as if the issue relates only to executives and shareholders, although other stakeholders can occasionally be affected by compensation policies. But a utility regulator has to examine issues more carefully because, for utility companies, executive compensation is not just a tug-of-war between shareholders and executives, it also involves a third party: ratepayers. Regulated utilities often consider executive compensation to be a normal business expense that is paid by ratepayers.

[98] This discussion is extracted from Lucian Arye Bebchuk and Jesse M. Fried, "Executive Compensation as an Agency Problem," *Journal of Economic Perspectives*, Vol. 17. No. 3, pp. 71-92 (Summer 2003).

At least in non-regulated corporations, which do not provide essential services the way utilities and health insurers do, the trade-off between executive pay and profit becomes an item largely of interest to shareholders. The price of goods and services traded in competitive markets does not have a specific component that rises when executives are paid more. Profits go up or down depending both on the pay package and competence of the executives. It is the job of the Board of Directors to balance these competing interests of shareholders and executives. While the public interest may be affected if managers are given incentives to skimp on labor or the environment, the issue is not as direct as if a utility can raise its price to pay for the compensation. The theoretical tension between management and shareholders regarding executive pay is clearly attenuated if the full test year executive salary expense can be included in rates charged to ratepayers. Managers, directors, and shareholders can all agree to reach into ratepayers' pockets to increase executive pay, since the money is not coming from shareholders' profits.

Without close scrutiny by regulators, ratepayers can only hope that the executive officers improve shareholder value by cutting costs and being productive (so that rates might decline by more than the executive bonuses) – rather than asking regulators for rate "relief" to increase profits (such as multi-year rate plans) or engaging in other practices that are likely to increase rates while enhancing shareholder rewards.

A regulatory commission must therefore ask broader questions, not just whether the compensation is similar to that requested by other utilities, and is appropriate to attract and retain talented managers and employees, but also (1) whether offering compensation similar to that of other utilities is just and reasonable in light of the methods by which compensation is set; (2) whether the "talent" that is being attracted and retained is necessary for the efficient operation of a regulated utility which benefits ratepayers; and (3) whether the compensation, in particular stock-based incentive compensation, aligns the interests of utility management not only with its shareholders but with its ratepayers.

In essence, regulators must consider two separate questions. The first question is, "Should the cost be included in rates funded by ratepayers and if so, to what extent?" The second question (which only arises after the first question is answered affirmatively) asks, "Is the magnitude of the cost that it is sought to include in rates reasonable?"

Q. Is there a clear relationship between executive pay and performance?

A. Only at the highest level, but it is quite attenuated. At some level, it is reasonable to assume that the level of compensation paid to executives affect the ability of a company to attract and retain qualified individuals. For example, one will probably not find a good CEO of a large public company if one is only willing to pay $250,000. However, the link between higher pay and improved performance is not at all clear. For example, it is not clear that that a company will always get more talent for $2.5 million than $2 million or even for $10 million.

The former President of Harvard University, Derek Bok, wrote a book in 1993 (before the recent burgeoning of executive pay) entitled *The Cost of Talent*, suggesting that relationships between pay and performance might be difficult to discern. The point is summarized as follows:

> Derek Bok, a former president of Harvard University, has written a fascinating and courageous book that dares to suggest that there is something wrong with this kind of disparity. ... The most interesting part of "The Cost of Talent" is its series of case studies on the way compensation is determined in the six professions. **The point in each case is that these are highly imperfect markets, in which the buyers have little clear idea**

> **either of the quality of the people they are hiring or of the benefit in getting the right man or woman. What is it worth to a large corporation to hire the 16th-best as opposed to the 17th-best potential C.E.O.? And is Smith No. 16 or No. 17? Nobody knows, so bargaining over compensation is a highly subjective process, easily manipulated by incumbents.** [emphasis added] Medicine and law are not that different, Mr. Bok points out: insiders can command large fees from clients who are too ill informed either to shop or to bargain effectively."[99]

Q. What other considerations unique to regulation should a state commission consider?

A. A key point is that incentive compensation is not known and measurable. It varies with corporate performance, and long-term incentive bonuses vary with stock prices. 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.

2. Short-Term Incentives – The Team Share Program

Q. What is OG&E requesting for short-term incentive program funding?

A. OG&E requests that ratepayers fund the short-term incentive "Team Share Program" at target performance, based on the four-year average of

99 Krugman, Paul. Review of "The Cost of Talent," by Derek Bok. Available: www.pkarchive.org/economy/Bok.html.

performance from 2012 through 2015. This amounts to $13,172,271, plus $970,796 in payroll taxes.

Q. Will you describe the Team Share program in general terms?

A. The plan's goals include financial goals (Earnings Per Share and O&M expenses), and non-financial goals (customer service and worker safety). Line workers receiving team share have approximately 50% financial and 50% non-financial goals. The percentage of financial goals increases to 70% for corporate officers and 80% for the three top corporate officers.[100]

The two financial goals, Utility Earnings per Share and Utility and Enterprise Services O&M Expense, comprise 58% of the aggregate 2015 Team Share Target. The Earnings Per Share goal serves shareholders alone, as the incentive to increase shareholder return does not benefit ratepayers. The financial goal of controlling O&M costs provides immediate benefits to shareholders, and may provide benefits, in the future, for ratepayers. This assumes that controlling O&M does not result in deferring necessary maintenance.

OGE Energy's Team Share Program goals in 2015 (set for both the parent company and the utility), at target, for its Team Share Program are 42% programmatic, non-financial goals, including the rate of incident reports and customer satisfaction.[101] Fifty-eight percent of the target is based on financial goals, including Earnings Per Share and O&M spending. The financial percentage of goals differ by level of employee, increasing with the level of management responsibility rising from 50% for non-exempt line workers to 85% for the three top corporate officers.

The programmatic, non-financial performance goals, include reportable incident rates and customer satisfaction benefit both shareholders and

[100] AG DR 2-22, 2015 Payout.
[101] Calculated from AG DR 2-22, 2015 Payout.

ratepayers. Reportable incidents are related to costs of accidents. These accidents result in lost work time from employees, possible payouts to customers suffering injuries and increased insurance rates. Success in customer satisfaction tends to result in increased authorized return for the utility.[102]

Q. How has compensation under the Team Share program evolved over time?

A. Over the past four years, from 2012 through 2015, increases in Team Share incentive targets have disproportionately been concentrated among OGE Energy's top officers. The annual average increase of 3.45 percent masks large disparities in trends among different employee classifications. However, corporate officers got most of the aggregate growth. Corporate officers received 57% of the company-wide increase in target STIP compensation, and the three top officers got almost a third. Target short-term incentives for corporate officers rose at 15.4% per year, while that of all other employees, rose at an aggregate of 1.7% per year. In the extreme, short-term incentives for non-exempt staff actually fell in nominal dollars by 1.0% per year. Thus, my concerns about executive compensation, discussed above, appear to be borne out by the large and disproportionate increases in target STIP levels.

[102] "How Customer Satisfaction Drives Return on Equity for Regulated Electric Utilities; J. D. Power and Assoc., Andrew Heath and Dan Seldin, PhD, May 2012, and J. D. Power McGraw Hill Financial, A McGraw Hill Financial White Paper, Oct. 2015.

Table 11: Annual Trend in Team Share Target Expenditures, by Employee Class

Total Company	2015	2014	2013	2012	Annual change
Non-Exempt	7,814,092	7,646,058	8,079,110	8,063,033	-1.04%
Exempt	9,247,643	9,010,391	8,709,693	8,426,481	3.15%
Executive	2,921,994	2,792,933	2,585,226	2,497,016	5.38%
(Officers)	1,764,266	1,255,358	1,192,879	1,221,500	13.04%
(3 Top Officers)	1,974,165	1,638,260	1,428,445	1,218,791	17.44%
All Officers	3,738,431	2,893,617	2,621,324	2,440,291	15.28%
Total	23,722,160	22,342,999	21,995,353	21,426,821	3.45%
Total w/Out Officers	19,983,729	19,449,382	19,374,029	18,986,530	1.72%

Without "Officers" and "3 Top Officers", the annual increase in Team Share costs is 1.72%. Including those classes, the total program annual inflation is 3.45%.

Q. How has the Commission dealt with STIP compensation in the past?

A. The Commission has already adopted the policy that for the costs of incentive compensation to be included in rates, it must provide direct ratepayer benefits. In Docket No. 13-028-U, Entergy's 2013 general rate case, the Commission determined that most, if not all, of the short-term incentive costs were indirectly tied to financial performance through Entergy's funding mechanism. The Commission concluded that EAI's shareholders benefit from financially-based compensation. As a result, the Commission ordered that ratepayers should bear no more than 50% of the incentive program costs.[103] Upon rehearing, the Commission confirmed its decision, writing that incentive compensation must have a direct ratepayer benefit before being included in rates.[104]

The Commission also revised the settlement of Docket No. 15-011-U to assign 50% of financially based incentives to shareholders[105] and revised the

[103] Docket 13-028-U, Order No. 21, p. 54
[104] *Id.*, Order No. 35, p. 23
[105] Docket 15-011-U.

settlement of Docket No. 15-015-U to follow the precedent of Docket No. 13-028-U and assign 50% of EAI incentives to shareholders.

Q. What do you recommend?

A. I recommend a single-year baseline calculation for incentives as a transition into the Formula Rate Plan true-up that I propose. I make two adjustments.

First, the target for corporate officers should be set on a *pro forma* basis to rise at 5.38% per year (the level at which incentives for non-officer executives increased from 2012-2015) when calculating incentive levels. OG&E has not demonstrated that it is reasonable and necessary for utility service to give executives an annual increase of 15% in target incentives while these incentives average at or below inflation for the rest of the corporate workforce. I use the officers' actual incentives as a percentage of target, but reduce the total to the lower targets that should be funded by ratepayers.

Once the baseline is set, I recommend sharing financial incentives 50-50 between ratepayers and shareholders for the reasons given above and following other past precedents.

For non-financial incentives, I also recommend actual 2015 results (paid out in the test year). In 2013-2015, non-financial performance (customer service and safety) has been below average, and ratepayers should pay for the actual level of performance they receive. Shareholders should not get extra money from ratepayers by averaging in 2012.

Q. Will you calculate your recommended short-term incentives?

A. Incentives are calculated in the table below based on 2015 payouts. I recommend that the Commission allow $5,427,562, as compared to OG&E's recommendation of $14,143,068. This is a reduction of $8,715,505.

Table 12: Calculation of AG Recommended Ratepayer Funding of Team Share

	2015	2015		less 50% of		
	target	total actual	utility expensed	financial	allowable per AG	utility expense
non-ex	7,814,092	3,596,045		(1,172,114)	4,768,159	
exempt	9,247,643	4,801,376		(1,733,933)	3,067,443	
executive	2,921,994	1,642,453		(657,449)	985,004	
officers utility	894,300	470,402		(201,218)	269,184	
officers HC	869,965	457,602		(195,742)	261,860	
3 top officers	1,974,165	941,395		(423,035)	518,359	
all officers	2,868,465	1,411,797		(624,253)	787,544	
total	23,722,160	11,909,273		(4,383,491)	7,525,782	
utility		8,091,775	5,333,289	(2,873,901)	5,217,874	3,439,101
holding company		3,817,498	2,968,105	(1,509,590)	2,307,908	1,794,398
adjust officer target util	(329,443)	(173,287)	(114,214)	74,125	(99,162)	(65,358)
adjust officer target HC	(5,430)	(2,856)	(2,221)	1,222	(1,634)	(1,271)
adjust 3 top officer target HC	(547,944)	(261,291)	(203,154)	117,417	(143,874)	(111,862)
total adjusted	22,839,343	11,471,838	7,981,805	(4,190,728)	7,281,111	5,055,008
		for comparison		recommended		
	booked TY	OG&E 4 yr avg.	OG&E adjustment	2015 per AG	AG adjustment	Utility > AG
Utility	9,304,421	12,728,936		5,118,712		
65.91% expensed	6,132,544	8,389,642	2,257,098	3,373,743	(2,758,801)	5,015,899
Holding Company	4,407,402	6,151,292		2,162,399		
77.75% to utility	3,426,755	4,782,630	1,355,874	1,681,265	(1,745,490)	3,101,364
Expensed STIP	9,559,299	13,172,271	3,612,972	5,055,008	(4,504,291)	8,117,263
Payroll Tax at 7.37%		970,796	266,276	372,554	(331,966)	598,242
AG Adjustment		14,143,068	3,879,248	5,427,562	(4,836,257)	8,715,505

The results are compared to OG&E's below to show the components of the difference.

Table 13: OG&E versus AG Recommendations for Ratepayer Funding of Team Share

OG&E	14,143,068
subtract to 2015 actual	(5,229,862)
subtract 50% financial	(3,293,998)
subtract excess officer pay	(191,646)
AG recommendation	5,427,562

Q. Have you made similar calculations using a four-year average?

A. While I do not recommend a four-year average, I made the calculations in the chart below. If an average is used, the same principles would apply. With a four-year average, I would still recommend a reduction of $4,613,641 from the utility's position based on removing half of financial compensation, a small amount of incentive compensation based on the workplace safety for unregulated Enogex activities in 2012-13, and a smaller amount of excess officer costs than in 2015.

Table 14: Calculation of AG Ratepayer Funding of Team Share if Four-Year Average is Adopted

	2015	AG 4-year average		less 50% of	less Exogen		
	target	total actual	utility expensed	financial	unregulated	allowable per AG	utility expensed
4 year average							
non-ex	7,900,573	6,732,546		(1,973,794)		4,758,752	
exempt	8,848,552	7,512,966		(2,433,352)		5,079,614	
executive	2,699,292	2,254,808		(877,270)		1,377,538	
officers utility	693,690	494,505		(196,014)		298,491	
officers HC	664,811	609,385		(237,399)	(12,916)	359,070	
3 top officers	1,564,915	1,286,148		(655,101)	(23,075)	607,973	
all officers	2,923,416	2,390,038		(1,088,513)	(35,991)	1,265,534	
total	22,371,833	18,890,358		(6,372,929)	(35,991)	12,481,438	
adjust officer target (utility)	(170,627)	(121,633)		48,213		(73,420)	
adjust officer target (HC)	(1,357)	(1,244)		485	26	(733)	
adjust 3 top officer target	(244,219)	(200,715)		102,234	3,601	(94,880)	
total adjusted	21,955,630	18,566,765		(6,221,997)	(32,363)	12,312,405	
utility	15,743,475	12,982,767	8,556,942	(3,716,229)		9,266,538	6,107,576
holding company	6,212,155	5,583,998	4,341,558	(1,991,840)	(32,363)	3,559,795	2,767,740
		for comparison		recommended			
	booked	utility 4 yr avg	utility adjustment	AG 4 yr avg.	AG Adjustment	Utility exceeds AG	
Utility	9,304,421	12,728,936		9,266,538			
65.91% expensed	6,132,544	8,389,642	2,257,098	6,107,576	(24,968)	2,282,066	
Holding Company	4,407,402	6,151,292		3,559,795			
77.75% to utility	3,426,755	4,782,630	1,355,874	2,767,740	(659,015)	2,014,889	
Expensed	9,559,299	13,172,271	3,612,972	8,875,316	(683,983)	4,296,955	
Payroll Tax at 7.37%	704,520	970,796	266,276	654,111	(50,410)	316,686	
AG Adjustment	51,923	14,143,068	3,879,248	9,529,427	(734,393)	4,613,641	

Q. How do you recommend that short-term incentives be calculated under a formula rate plan?

A. I recommend that the FRP be set on a going-forward basis based on target (except that corporate officers are reduced to a *pro forma* target with maximum 5.38% increase per year from 2012 to the FRP year for corporate officers), minus 50% of financial incentives assigned to shareholders.

To true up from target to actual performance, actual year incentives would be the starting point (except for any reduction arising from the *pro forma* cap on the target for corporate officers). I then recommend that 50% of financial incentives be removed up to target and 75% above the target for aggregate financial incentives. Thus, for example, if actual performance were 150% of target, I would recommend removing 50% of 100% + 75% of 50%, leaving an incentive payment by ratepayers of 62.5% of target. I make this recommendation because (1) when performance is above target, shareholders can afford to pay it, and (2) the potential for performance above target is enhanced by the FRP and other riders proposed by OG&E, so that ratepayers would already be paying to enhance the opportunity for OG&E employees to exceed financial targets.

3. Long-Term Incentive Compensation

Q. What does OG&E recommend that ratepayers pay for long-term incentives?

A. In updated Workpaper WP C-2-38, OG&E had test year costs of $4,914,167[106] and proposed to increase it to $5,908,912 on a pro forma basis for a four year average. At OG&E's 7.37% payroll tax percentage, OG&E requests an additional $435,487 in payroll taxes for a total of $6,544,399.

Q. Please describe OGE's Long-Term Incentive Program.

A. As OGE notes in its Joint Proxy Statement, "Payouts of annual and long-term incentive awards require the achievement of specific goals established by the Compensation Committee that are designed to benefit our shareholders and the Company…"[107]

The amount of performance stock that executives receive is divided into two categories – 75% based on total shareholder return over a three-year period, and 25% based on OG&E (utility) earnings per share (EPS).

[106] Total amounts les capitalized percentages on this workpaper.
[107] OGE Proxy Statement and Notice of Annual Meeting, May 19, 2016, p. 20

For the total shareholder return component of performance stock, if total shareholder return is below the 35th percentile, executives receive nothing. They receive 100% of the target at median and up to 200% of the target at the 85th percentile or higher.[108] Thus, performance shares focus executives on the stock price doubly – by giving them more shares if shares are more valuable relative to their peers.

For the Earnings Per Share component, the EPS starts with a base year (2014 for 2015 shares awarded), and targets growth in EPS, with nothing if growth in EPS is less than 1.5%, 100% at 4.5%, and 200% at 7% EPS growth.

The value of the shares is strictly equity-based, rising and falling in value with Company stock prices. The goal of this program, as stated, is to link the interests of program participants and shareholders, even more closely than do short-term incentives. There are no specific and clear ratepayer benefits from a higher OGE Energy share price.

Q. Is stock-based compensation known and measurable at the time it is awarded?

A. Absolutely not. There is an actuarial estimate of the value of that stock-based compensation, but what is awarded at the end of the three-year period can vary wildly. OG&E is a case in point. OGE Energy's 2015 payout of 2013 LTIP awards was **ZERO**. Total shareholder return was below the 35th percentile of the peer group and EPS growth was below 2.5% per year (because of impairments at Enable). [109] Yet, OG&E booked $5,291,000 of expenses in 2013 for LTIP.[110]

Q. Does stock-based compensation have more value for shareholders than an equivalent amount of cash compensation for executives?

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[108] *Id*., p. 35.
[109] *Id*., May 19, 2015, p. 29.
[110] AG DR 2-15.

A. Yes. Stock-based compensation has significant value for shareholders – enough that they, through their board of directors, are willing to pay for it out of their own pockets in most states where rate recovery is not allowed, rather than shifting into another form of compensation (such as base salary) which is not generally disallowed.

Shareholders want to focus their executives on raising stock prices. Stock options and performance-based shares are particularly effective because the executives get less compensation if the stock price increase lags the market or does not rise at all over a period of time. The fact that this compensation is largely not paid out in cash is also beneficial to shareholders. Shareholders also benefit because stock-based compensation is positively correlated with share prices. More stock-based compensation is paid when shareholders are doing well, while compensation is less or zero if shareholders are not doing well.

Q. Do a number of utilities offer LTIP to executives even if ratepayers do not fund stock-based compensation?

A. Yes. Many utilities offer stock-based LTIP programs even after their regulators have disallowed them (or even if they have not requested rate recovery for them). Many states do not allow LTIP in rates. For example, Entergy has had LTIP disallowed in Arkansas and Texas for at least 9 years, but it continues to offer a large LTIP program (and no longer requests funding for it in rates in either state). Southern California Edison Company maintained its LTIP program after it was first disallowed in 2009 and again in two subsequent rate cases. Pacific Gas and Electric Company has an LTIP program, even though it has never requested funding for that program in rates. El Paso Electric offers LTIP even though Texas has not allowed financially based incentives in rates for at least a decade, and the New

Mexico Public Regulatory Commission recently disallowed LTIP.[111]

Q. What conclusions would you draw from this phenomenon?

A. Stock-based compensation must have significant benefits to shareholders. The only reason a company would continue to operate a stock-based compensation program after a disallowance would be if it believed that the benefit to it and to its shareholders outstripped the cost to the company and its shareholders. In other words, the fact that utilities continue to compensate their executives with stock after their regulators have disallowed such compensation indicates that they believe that they stand to gain by an amount that is greater than the cost resulting from the disallowance.

Q. What are the impacts on ratepayers when the focus of the CEO and other top executives is on shareholder earnings and share prices?

A. It is not clear that ratepayers are benefited significantly, as they may also be harmed. In theory, higher earnings and share prices could mean a stronger company with a lower cost of funds. But OG&E has provided no evidence that utility financial performance is linked to ratepayer benefits from lower cost financing and adequate capital for infrastructure investment and no evidence that paying executives for higher share prices results in lower cost financing. Thus, any assumption that providing incentives to management based on share price or income will improve the utility's financing costs by material amounts is unsupported.

Moreover, the finance literature does not strongly support a strong correlation between incentive compensation for executives with a stronger company and stronger financial performance. Cooper, Gulen, and Rau have found that firms with CEOs who receive the highest levels of pay, and particularly higher levels of cash-based and stock-based incentives, earn

[111] Case No. 15-00127-U, Final Order Partially Adopting Recommended Decision, pp. 44-45, 47. ("The Commission's general policy is to exclude financially driven incentive compensation.").

abnormally low stock market returns.[112] Another study by Moody's links higher executive compensation (and particularly higher incentive compensation) with higher rates of defaults and bond rating downgrades after controlling for overall corporate performance.[113]

Additionally, when we look at the utility industry, there are a number of ways in which earnings per share and stock prices can be increased. While some might benefit ratepayers, many do not. An example of ratepayers benefiting would be to reduce costs by being more productive (so that shareholders make money in the interim but costs in the next rate case are lower). However many means of raising share prices and earnings would be detrimental to ratepayers. These include activities such as:

- Reducing costs by curtailing work between rate cases (gaining money for shareholders in interim years). This either creates cyclical spending, with higher spending in test years that is included in rates, or even worse, creates deferred maintenance to the point that extra costs beyond cyclical increases must be incurred to catch up.

- Reducing costs to the point that quality of service is reduced.

- Convincing regulators to raise rates (*e.g.*, to cover costs such as long-term incentive compensation which are not recovered in all states or to keep rates of return at relatively high levels).

- Developing infrastructure improvement programs which may be of questionable value but raise rate base.

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[112] Michael J, Cooper, Huseyin Gulen, and P. Raghavendra Rau, "Performance for Pay? The Relationship between CEO Incentive Compensation and Future Stock Price Performance," May 2010. Working paper, available at SSRN: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1572085.

[113] Kenneth Bertsch and Chris Mann, Moodys, Special Comment: CEO Compensation and Credit Risk, July, 2005.

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- Making tax-timing elections between rate cases that may benefit shareholders in early years at the expense of ratepayers in later years.[114]

In addition, some managerial actions may have little direct impact on ratepayers (for example, changes in unregulated activities by the company owning the utility or mergers and acquisitions). But such actions may have indirect impacts, by diverting attention of utility managers from managing the regulated utility, suggesting that ratepayers should not pay for long-term incentives that encourage these activities.

Thus, one cannot conclude that giving executives LTIP incentives to raise share prices and earnings will materially benefit ratepayers, and will not harm ratepayers or divert management attention to more lucrative pursuits than managing utility operations.

Q. What was the Commission's most recent decision in a litigated case regarding stock-based LTIP compensation?

A. The most recent decision of the Commission regarding long-term incentive compensation is in Docket No. 13-028-U Decision Order No. 21, followed by Decision Order No. 35 upon rehearing. In these decisions, the Commission concluded that EAI's long-term incentive compensation is based entirely on the financial performance of EAI and benefits shareholders."[115]

The Commission noted:

> With regard to EAI's stock-based and long-term incentive costs, the Commission agrees that EAI's long-term incentive do not provide material ratepayer benefits, or align the interest of shareholders and ratepayers because the focus of the incentive

[114] For example, Southern California Edison Company, Southern California Gas Company, and San Diego Gas and Electric company all changed accounting for new IRS rules on repair allowances between rate cases, enriching shareholders until the California PUC essentially reversed the practice. CPUC Dec. No. 15-11-021 (Southern California Edison) at 430-455. CPUC Decision No. 16-06-054 (Sempra Energy Utilities) at 169-208.
[115] *Id*, p. 5

> is on stock process and earnings per share rather on the provision of utility service.[116]

Therefore, the Commission disallowed 100% of long-term incentive program costs.

Q What do you recommend in this case?

A As with Entergy, OG&E's long-term incentives are based entirely on equity performance – stock price performance relative to peer companies and earnings per share, coupled with higher value awards when share prices are higher than when they are lower.[117]

The Commission should deny recovery of any expenses related to the executive Long-Term Incentive Program.

This is a reduction of $5,908,912 from OG&E's request plus $435,487 in payroll taxes for a total of $6,344,399.

B. *Directors' and Officers' Insurance*

Q. What has OG&E requested for Directors' and Officers' (D&O) liability insurance?

A. OG&E has made no adjustments to the cost of this insurance in its testimony, other than a minor adjustment for annualization in the *pro forma* year. It has requested recovery of 100% of the cost, or $1,103,971, shown in Workpaper C 2-14-2.

Q. Is D&O liability insurance an ordinary business expense?

A. No. D&O insurance is often called into play when shareholders of publicly-traded companies sue company management. D&O insurance provides a mechanism for aggrieved shareholders to collect funds under certain

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[116] Op Cit Order (No. 21), pp. 54-55.
[117] The same number of shares is worth more if share prices are higher.

circumstances. In the absence of insurance, many of the cases in which shareholders could collect funds (related to inadequate or misleading disclosures to shareholders of material company activities), would be below the line from the perspective of ratepayers, so that the insurance is insuring utility profits, not expenses covered by rates.

Because shareholders are often major beneficiaries of the payouts made under these insurance policies, the policies reduce the risk of common equity investment in the event of a bad decision by management or directors. In sum, D&O insurance is not an ordinary business expense because of <u>who gets the money</u> if the policy is called upon. These policies become a secondary source of income if the company's shareholders face adverse consequences. Because shareholders often get the money, they should share in the premium.

Q. Have any academic articles suggested that D&O liability insurance is inappropriate method for protecting directors' interests?

A. An article by M. Martin Boyer, then an associate professor of finance at the Université de Montreal, suggests that there are several means of protecting directors from personal liability, but D&O insurance "protects the shareholders' wealth more than the directors'."[118] He writes, "In a sense, shareholders purchase insurance for managers to protect them against shareholder lawsuits."[119]

It appears that Professor Boyer was not thinking of regulated utilities, where ratepayers are asked to purchase insurance to protect managers against shareholder lawsuits.

Q. What is your policy position with respect to ratemaking for the D&O liability insurance policy?

A. Because D&O insurance is not an ordinary business expense, it is not appropriate to allocate 100% of the cost of D&O insurance to utility ratepayers. Ratepayers should pay *something* for D&O insurance because the existence of the insurance does improve the ability to attract and retain qualified directors and officers and enables them to make decisions without fear of personal liability. But they should not pay the whole cost because the insurance mechanism is specifically designed to protect shareholders, and because shareholders often receive the funds from the policy. The reason to

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[118] Boyer, M. Martin, Directors' and Officers' Insurance and Shareholder Protection (March 2005). Available at SSRN: http://ssrn.com/abstract=886504 The abstract of this article states the following:

> Corporate directors are liable for the corporation's actions as well as their own. Strangely, and by far, the most likely plaintiffs in a lawsuit against corporate directors are the shareholders who appointed them in the first place. As a result, directors often require protection so that their personal wealth is not expropriated in the event of a good faith error. There are three ways to protect a director's wealth: Corporate indemnification plans, Limited liability provisions and Directors' and officers' (D&O) insurance policies. Of the three types of protection, D&O insurance is arguably the strangest not because shareholders purchase it to protect directors in case of a lawsuit, but because it also protects shareholders. Using an original database, I test a set of hypotheses that should determine the demand for D&O insurance. Similar to Romano (1991a) and Gutiérrez (2003), my analysis suggests that D&O insurance protects the shareholders' wealth more than the directors'.

[119] *Id.*, p. 3.

deny full funding for D&O insurance is because of who receives payments from the policy, and because the policy provides legal defense for lawsuits, which if lost or settled, would generally create claims below the line (*e.g.*, for misrepresentation of financial reports).

Instead, it is reasonable to share the cost of this insurance on a 50-50 basis between ratepayers and shareholders, since D&O insurance is often called into play when shareholders of publicly-traded companies sue company management.

Q. Have some state commissions shared D&O insurance between ratepayers and shareholders?

A. Yes. The APSC has adopted 50-50 sharing of such expenses, based on this rationale. In its Orders in four contested cases,[120] the Arkansas Public Service Commission adopted the 50-50 sharing of these expenses based on the rationale given above. Excerpts from two decisions are quoted below:

> The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayers.[121]

> The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission

[120] Dockets 02-227-U, 04-121-U, 04-176-U, and 06-101-U.

[121] Arkansas PSC Docket No. 04-121-U, Order No. 16, page 40, September 19, 2005 Available: www.apscservices.info/pdf/04/04-121-u_286_1.pdf .

therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer. [122]

Similarly, the California Public Utilities Commission has required a 50-50 sharing of this cost since 1996.[123] The 1996 decision specifically cited information brought forward by the Commission's Division of Ratepayer Advocates that the bulk of lawsuits using this insurance were brought by shareholders and that the one such shareholder suit that Southern California Edison settled resulted in a below-the-line payment of amounts less than the policy deductible. The Commission concluded:

> In D. 87-12-066, 26 CPUC 2d 392,422, we permitted these types of premiums to be recovered in rates. However, the statistics provided by DRA [Division of Ratepayer Advocates] from 1986-1993, which were not available in 1987 when we decided D. 87-12-066, illustrate that shareholders also benefit from this insurance. Therefore, we will allow half of the expenses requested by Edison for this item. By making this allocation, we are not implying that it is not necessary for Edison to maintain such insurance. To the contrary, we are funding half of the premium with ratepayer funds. However, to the extent that shareholders also benefit from this insurance, they should also share in the expense.[124]

In 2009, the Public Utilities Commission of Nevada reversed a precedent from 1991 and adopted 50-50 sharing of this expense, stating that "in this instance, the Commission is persuaded by BCP [Bureau of Consumer Protection] that shareholders receive a tangible benefit from D&O liability coverage and should participate in its cost."[125]

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[122] Arkansas PSC Docket No. 06-101-U Order No. 10, Page 70, June 15, 2007, footnote omitted. Available: www.apscservices.info/pdf/06/06-101-u_303_1.pdf

[123] California PUC Decision No. 96-01-011 in Application No. 93-12-025 slip. op. at 140-141, January 15, 1996, regarding Southern California Edison Company; and California PUC Decision No. 00-02-046 in Application No.. 97-12-020, slip op. at 309, February 17, 2000, regarding Pacific Gas and Electric Company.

[124] CPUC Decision No. 96-01-011, p. 141.

[125] Public Utilities Commission of Nevada, Order in Docket 08-12002 (June 24, 2009), p. 149.

The Connecticut Department of Public Utility Control has gone a step further, requiring ratepayers to pay just 25% of the cost of D&O insurance cost since 2006. Its January 27, 2006 Decision in Docket 05-06-04 (for United Illuminating) stated:

> The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134,430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility. The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.[126]

Q. What is the effect of your proposed 50%-50% sharing of D&O insurance?

A. My recommendation is to adjust the cost of D&O insurance down to $551,986 to assign 50% of the test year amount to shareholders.

Q. Is there a rate base reduction arising from this change?

A. Yes. The prepayments for D&O insurance should also be shared on a 50-50 basis based on the new prepayment. The prepayment (an element of rate

[126] Connecticut DPUC Decision in Docket 05-06-04 (United Illuminating Company) January 27, 2006, p. 47. The DPUC reconfirmed its precedent of allowing only 25% of D&O liability insurance in rates in its Decision in Docket 08-07-04 (United Illuminating Company) February 4, 2009 at page 43.

base) would have an average amount of about $551,896,[127] of which 50% or $275,948 should be adjusted out and assigned to shareholders.

C. *Normalize Fluctuating Expenses*

1. Employee-Related Costs

Q. What fluctuating expenses did you analyze related to employee-related costs?

A. I reviewed four sets of employee-related costs that are amenable to averaging: severance, signing bonuses, retention bonuses, and relocation expenses. In each case, I found that test year costs exceeded normal costs over recent years and normalized them using a 5.75 year average. I recommend reducing OG&E's expenses by $356,393 plus payroll taxes on severance and bonuses (but not relocation) of $23,221, for a total of $379,614.

a. Severance

Q. What is OG&E's test year severance expense?

A. It is $739,091 (total company). The figure is made up of $477,132 for the holding company (after removing unregulated costs not assigned to the utility) and $261,959 for the utility itself.

Q. Is this figure representative?

A. No. The Test Year was the second-highest of the last six years, and it was higher than either 2015 or 2016 year-to-date figures, showing that severance was concentrated in the last half of 2015 and the first half of 2016. The table below (taken from AG DR 2-1) shows the information.

[127] Half the amount of the insurance premium.

Table 15: Severance Expenses 2011-2016

	OG&E	OGE Energy	
2011	$278,671	$197,681	$476,352
2012	$1,102,737	$308,277	$1,411,014
2013	$599,364	$319,462	$918,826
2014	$139,102	$12,171	$151,273
2015	$55,039	$454,404	$509,443
TY	$20,102	$969,392	$989,494
2016 YTD	$63,997	$625,201	$689,198
5.75 year avg	$389,376	$333,425	$722,801
adjustment	($369,274)	$635,967	$266,693

Q. Are there other reasons why high severance costs should not be adopted?

A. There can be a mismatch between the severance costs paid in a given year and the reduction in labor expenses from the employees who are given severance payments.

Q. What is your recommendation?

A. I recommend setting severance based on a 5.75 year average (2011-2016 YTD), which is $722,801, a downward adjustment of $266,693 (about 27% below the test year figure) on a total company basis.

b. Signing Bonuses

Q. What is OG&E's test year signing bonus expense?

A. It is $89,000 (total company), based on AG DR 2-3.

Q. Is this figure representative?

A. No. Test Year signing bonuses appear mathematically impossible because the test year expense of $89,000 is higher than the total expense for calendar year 2015 and 2016 year-to-date (including the full test year), which is only

$22,322. The table below (from AG DR 2-3), shows expenses over the most recent period of 2011-2016YTD.

Table 16: Signing Bonus Expenses 2011-2016

	OG&E	OGE Energy	Total
2011	$36,000	$13,000	$49,000
2012	$22,000	$13,000	$35,000
2013	$60,040	$70,500	$130,540
2014	$93,000	$17,500	$110,500
2015	$11,900	($2,568)	$9,332
TY	$71,000	$18,000	$89,000
2016 YTD	$10,000	$3,000	$13,000
5.75 year avg	$40,511	$19,901	$60,413
adjustment	$30,489	($1,901)	$28,587

c. Retention Bonuses

Q. Do you have any adjustment to retention bonuses?

A. Yes. Retention bonuses were $62,805 in the test year. The average of retention bonuses was $96,490, but a single executive (named in the proxy statement) who transferred from Enable to OG&E was given a retention bonus of $250,000 in 2015.[128] I remove from the average the cost of this unusual compensation to this single executive. This brings the five-year average of retention bonuses to $53,011, which is $19,794 less than the test year figure.

[128] OGE Proxy Statement and Notice of Annual Meeting, May 19, 2016, p. 32

Table 17: Retention Bonuses 2011-2016

	OG&E	OGE Energy	Total
2011	$95,000	$8,514	$103,514
2012	$10,000	$8,514	$18,514
2013	$15,107	$22,876	$37,983
2014	$74,305	$15,000	$89,305
2015	$265,500	$20,000	$285,500
TY	$62,805	$10,000	$72,805
2016 YTD	$20,000	$0	$20,000
5.75 year avg	$83,463	$13,027	$96,490
adjust for executive	($43,478)	$0	($43,478)
adjusted average	$39,985	$13,027	$53,011
adjustment	$22,820	($3,027)	$19,794
with payroll tax 7.37%			$1,459
total adjustment			$21,252

Q. Have you reviewed relocation costs?

A. Yes, by asking for information in AG DR 2-2.

Q. Do you propose any adjustments?

A. Yes. Relocation expenses were also above long-term averages.

Table 18: Relocation Expenses 2011-2016

	OG&E	OGE Energy	Total
2011	$0	$817,998	$817,998
2012	$0	$586,591	$586,591
2013	$248,922	$706,032	$954,954
2014	$24,000	$1,291,696	$1,315,696
2015	$10,200	$1,277,127	$1,287,327
TY	$7,500	$946,754	$954,254
2016 YTD	$0	$286,808	$286,808
5.75 year avg	$49,239	$863,696	$912,935
adjustment	($41,739)	$83,058	$41,319

I recommend setting relocation costs based on a 5.75-year average which is $60,413, a downward adjustment of $28,587 (total company).

2. Storm Damage

Q. What was OG&E's storm damage expense related to Arkansas in the Test Year?

A. Including distribution costs directly assigned to Arkansas and transmission and generation expenses allocated to Arkansas, the total was $373,360, of which $87,423 was straight-time labor.

Q. What is OG&E's request for storm damage expense in this case?

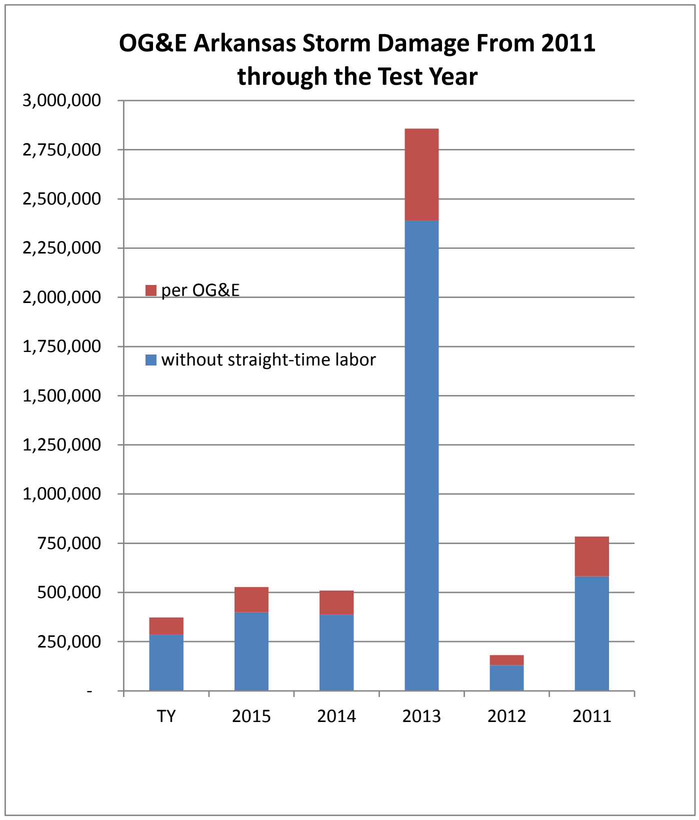
A. OG&E requests Arkansas-jurisdictional storm damage of $1,066,714, an increase of $693,354. This is based on an average of the test year and the three preceding years (2013-2015).

Q. Why is this average unreasonable?

A. There are two reasons. The first is that the portion of storm damage expenses that are averaged should not include straight-time labor. All of the company's straight-time labor is captured in the payroll adjustment. To average in more straight-time payroll from earlier years of storm damage has the effect of making ratepayers pay the Company for more payroll than actually exists.

The second reason is that OG&E picked a very unusual period for calculating storm damage. As shown in the figure below, 2013 storm damage was very unusual – 3.6 times the amount in the next highest year from 2011-2015.

Figure 3: Arkansas Storm Damage Expenses 2011-Test Year



Q. Do other utilities average storm damage over longer periods than three years?

A. Yes. For example, Entergy Arkansas uses a five-year average, as approved by the Commission.[129]

Q. What do you recommend for storm damage?

A. I do not include straight-time labor in storm damage costs and use an average from 2011 through the Test Year. This takes OG&E's figures back through the effective year of its last rate case. As shown in the table below, my estimate of storm damage is $695,529. This figure is $409,592 above the $285,937 incurred in the Test Year excluding payroll and $371,185 less than OG&E's estimate. The table below shows the information.

[129] Direct Testimony of S. Brady Aldy on behalf of EAI in Docket 15-015-U, pp. 14-15, citing Docket 13-028-U, Order No. 21 at 186.

Table 19: Attorney General's Storm Damage Adjustment

	TY	2015	2014	2013	2012	2011		OG&E 2013-TY	AG 2011-TY
without straight-time labor	285,937	399,154	385,444	2,390,880	129,861	581,899		865,354	**695,529**
straight-time labor	87,423	127,747	123,824	466,449	51,357	201,857		201,361	176,443
per OG&E	373,360	526,901	509,267	2,857,329	181,217	783,755		1,066,715	871,972
OG&E Adjustment from OG&E Expense Level								693,355	
AG Adjustment from AG Expense Level									409,592

D. ***Advertising Expenses***

Q. What was OG&E's reduction to its booked advertising expenses, including costs of energy efficiency programs?

A. As shown in Schedule C-7 as revised, the table below shows OG&E's booked spending and costs it removed either as unrecoverable promotional advertising, related to the Oklahoma wind rider, or related to energy efficiency programs. The table also shows additional adjustments that I discuss below. The end result is that I recommend removing $114,824 of expenses that OG&E included as ratepayer-expenses. The basis for these adjustments is my review of APSC DR 35.

Table 20: AG Proposed Disallowance of Advertising Expenses

	Booked	OG&E Removed	Remainder	Additional AG Removed	AG Remainder
909	$3,467,414	$3,147,986	$319,428	$ 92,712	$226,716
913	$ 18,748	$ 53,301	$ (34,553)	$ 14,812	$ (49,365)
930.1	$ 7,300	$ -	$ 7,300	$ 7,300	$ -
Total	$3,493,462	$3,201,287	$292,175	$ 114,824	$177,351

Q. Based on the response to APSC-35, what costs did you remove from Account 909 that OG&E proposed to recover from ratepayers?

A. Yes. I removed $92,712 from "Advertising – Safety OK", which contains $42,500 in sponsorships (of a rodeo and the Myriad Gardens foundation in

Oklahoma City) and $50,212 in advertisements providing information on Oklahoma's recently passed law against texting while driving. These texting advertisements were not necessary to provide utility service. There is no clear nexus between utility ratepayers and advertising about safe driving.

I also removed $28,835 to advertise Arkansas energy efficiency programs. Other similar costs had been removed. These costs may be reasonable for recovery, but should not be recovered in base rates. Even if OG&E actually failed to recover these costs in the energy efficiency rider, it was a mistake that makes the test year figures unrepresentative.

The total removed from this account is $121,547.

Q. Based on the response to APSC-35, what costs did you remove any costs from Account 913 that OG&E proposed to recover from ratepayers?

A. There were $14,812 of inappropriate expenses including hats, shirts and other promotional gear, gift cards, sponsorships, golf, flowers, etc. These costs should not be paid by ratepayers.

Q. Were there any other questionable expenses in Account 913 shown in the response to APSC-35?

A. Yes, $19,455 of Human Resource Department expenses, largely related to recruiting and safety activities wound up in Account 913. After removing two items for gear included above, the remainder is $19,211. These are legitimate expenses, but they are in the wrong FERC Account. Human Resources is not a sales and marketing activity related to customers that should be charged over 80% to the residential class; it is an administrative cost of the whole company. I therefore reclassify $19,211 from Account 913 to Account 921.

Q. Does the response to APSC-35 show any inappropriate costs for recovery from ratepayers in other accounts?

A. Yes. OG&E included $7,300 in Account 930.1 for "retail energy appreciation" which turned out to be catering costs at an Oklahoma City Dodgers game, a cost that ratepayers should not pay.

E. *Dues and Donations*

Q. Will you comment on adjustment C2-33 and Schedule C-6?

A. In AG DR 9-05, I requested information on industry dues ($177,045) as requested by OG&E, excluding the Edison Electric Institute.

From this information, I recommend that $7,357 be removed-- $6,000 for a southwest Power Pool membership for OGE Transmission LLC, which is not part of the regulated utility[130] and $1,307 for miscellaneous invoices including the Arkansas Association of Professional Lobbyists (below the line), a donation to a community college, Oklahoma Chamber of Commerce dues (assigned to Oklahoma by OG&E in the other portions of Schedule C-6), and "Ted's Café."

I also recommend that dues for Scientech and Intertek USA be reclassified to Account 506 (steam production miscellaneous operating expenses) because they involve computer programs essential to the efficient operation of steam generating plants. This reclassification moves $158,362 from Account 930.2 to Account 506.

I also reviewed documentation on Information Education and Safety costs of $84,564. Of this amount, Arkansas ratepayers should pay only a share of $5,940 (of which $3,940 for the One-Call System for marking and locating

[130] According to the following document in OG&E's recent Oklahoma rate case: https://secure.oge.com/OkRateCase2/Data%20Request%20Responses/TASC-1/OIEC-7/OIEC%207-10_Att.pdf

underground lines). The remainder is $8,124 for sponsorships and tickets[131] that ratepayers should not pay at all, and $70,500 in costs that, if chargeable to ratepayers, should be directly assigned to Oklahoma (for a green schools program, an economic development program, an Oklahoma public policy academy, and clean-up of Oklahoma highways).

Q. Did you obtain information on Schedule C-6HC (holding company expenses in the same area)?

A. Yes. Aside from the Edison Electric Institute, which I will discuss separately, OG&E spent $60,588 on Industry dues, and $93,716 on Info/Education and Safety at the holding company level. I remove $3,250 for the Oklahoma Oil and Gas Association (30% for lobbying based on its invoice, while splitting the remainder 50-50 between OG&E and its oil/gas pipeline affiliates), and $30,504 from "Info/Education/Safety: for sponsorships, donations, a speakers' ball, hats, a golf tournament, and similar items. I then remove an additional $11,529 for industry dues and $13,110 on other costs to apply the "distrigas" subtraction of 20.74% from Holding Company expenses other than the Oklahoma Oil and Gas Association, where my allocation to non-utility activities was higher.

Q. Will you comment on the Edison Electric Institute?

A. OG&E charges $725,790 in EEI dues to ratepayers out of approximately $840,000.[132] It allocates 13% of regular dues and 26% of Industry Issue dues to below-the-line accounts for lobbying.

Q. Is this an adequate reduction?

A. No. EEI spends money on many other things that do not fit the narrow definition of lobbying but that ratepayers should not pay for (and would not

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[131] They provided a sample of 5 of 30 miscellaneous invoices totaling $7,124. All sampled invoices were for tickets and sponsorships.

[132] Schedule C-7 as updated.

pay for if OG&E spent the money directly). EEI also spends money on legislative advocacy, regulatory advocacy, marketing, public relations and advertising, donations, and club dues. After a series of regulatory disallowances of significant parts of EEI dues across the country, EEI has stopped issuing detailed information on its budget, previously available under the auspices of the National Association of Regulatory Utility Commissioners (NARUC).[133]

In the previous OG&E case, Staff recommended a reduction of 31.17%, based on material provided in response to APSC DR 52.03, which showed some of EEI's costs beyond legislative advocacy. I recommended a larger number (49.93%) by including information from past years on EEI's regulatory advocacy expenses that EEI failed to give to OG&E in that case.

In this case, OG&E was given the opportunity to provide the same information that it provided to Staff in Docket No. 10-067-U, but it simply failed to answer the question. When asked for the same information provided in APSC DR 52.03 in the last case, OG&E responded with only bare lobbying expenses. Exhibit WM-6 contains the response to APSC 52.03 in Docket No. 10-067-U, and the response to APSC 77.03 in this case, showing the difference.

Q. Has EEI engaged in activities in recent years which are questionable expenses for ratepayers?

A. Yes. In recent years, EEI has been involved in extensive regulatory advocacy, public relations, and advertising efforts related to solar energy. EEI embarked on a political advertising campaign against net energy metering for solar energy in Arizona with California utility money. It has

[133] Response to Initial Requests for Information (Question 65) of the Kentucky Attorney General (August 27, 2008) from Kentucky Public Service Commission Case No. 2008-00251 and 2007-00565 for Kentucky Utilities Company, found at http://psc.ky.gov/pscscf/2008%20cases/2008-00251/KU_Response%20to%20AG's%20Requests%20dated%20082708%20(Vol%201of3)_091108.pdf.

paid for a white paper calling distributed solar photovoltaic energy a threat to the utility industry[134] and has backed it up with testimony in an Arizona Corporation Commission case and advertising in Arizona.[135] And it will not even disclose what it is spending on these activities.[136] Whatever one might believe about the substance of EEI's claims, these activities to fight solar energy in other states are clearly not causes that captive Arkansas utility ratepayers should be paying for through their rates.

Q. What do you recommend?

A. In light of OG&E's failure to bear its burden of proof and failure to provide even the limited information requested by APSC Staff, I recommend that the Commission disallow all funding for EEI, except $10,000 for mutual aid activities. This is a reduction of $715,790. Failure to provide any information on EEI's spending, even the limited amount requested by Staff does not meet the burden of proof that expenditures are reasonable and necessary for utility service.

In the alternative, the Commission should remove the $15,000 donation to the Edison foundation (which as a contribution should be below the line) and an additional $297,000 (50% of EEI's total funding other than this donation less the below the line amount originally identified by OG&E). The alternative adjustment totals $312,000.

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[134] Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," Prepared for Edison Electric Institute, January 2013. http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf .

[135] Peter Kelly-Detwiler, EEI Commercial on Net Metering: at Risk of Polarizing the Debate" Forbes, December 3, 2013. http://www.forbes.com/sites/peterdetwiler/2013/12/03/eei-commercial-on-net-metering-at-risk-of-further-polarizing-the-debate/ . The EEI television advertisement is shown on this website. http://breakingenergy.com/2013/11/12/energy-quote-of-the-day-i-shouldnt-have-to-pay-for-my-neighbors-solar/ A quotation from the advertisement: "I shouldn't have to pay for my neighbor's solar." Adam Browning, Greentech Solar: Edison Electric Institute Really Does Not Want You to Go Solar. http://www.greentechmedia.com/articles/read/In-Rare-Public-Filing-Edison-Institute-Downplays-Value-of-Solar-For-Arizon EEI's Formal Comments in Arizona are given here: http://s3.amazonaws.com/dive_static/diveimages/EEI.pdf

[136] Patrick O'Grady, "Edison Electric Institute enters net metering fray with Arizona ad buy," Phoenix Business Journal, November 5, 2013. http://www.bizjournals.com/phoenix/blog/energy-inc/2013/11/edison-electric-institue-enters-net.html?page=all

Q. Will you summarize your adjustments for Dues and Donations on Schedule C-2-33 in addition to OG&E's adjustments?

A. The table below shows $883,102 in additional revenue requirement adjustments, of which $725,790 is for the Edison Electric Institute, $157,312 for other organizations. In addition, $158,362 is reclassified from Account 930.2 to Account 506 to reflect the purpose of the expense.

Table 21: AG Proposed Disallowance and Reclassification of Dues and Similar Costs

Chamber of Commerce	$ (12,938)	directly assigned to Arkansas
Industry Dues		
Disallow	$ (7,357)	
Reclassify to Account 506	$ (158,362)	
Edison Electric Institute Holding Company	$ (725,790)	
Oklahoma Oil & Gas Assn. Holding Company	$ (3,250)	
Distrigas remaining holding company (20.74%)	$ (11,529)	
Info/Education and Safety		
Disallow	$ (8,124)	
Directly Assign to Oklahoma	$ (70,500)	
Disallow holding Company	$ (30,504)	
Distrigas Holding Company	$ (13,110)	
Total Reductions from Schedule C-6 additional to OG&E reductions	$ (1,041,464)	
Addition to Account 506	$ 158,362	
Net Reduction	$ (883,102)	

F. *Non-Recurring Inventory Reduction*

Q. Did you review costs booked to Account 910 in the process of reviewing advertising and marketing expenses?

A. Yes. In the response to AG DR 2-39, I found that OG&E made an accounting adjustment for $132,338. I requested additional information on this adjustment in AG DR 10-01 and found that it was a write-off of in-home display inventory associated with the Smart Hours program.

Q. What do you recommend regarding this item?

A. This item is unusual and non-recurring, and it should not be included in Test Year expenses.

G. *Rate Case Expenses*

Q. What did OG&E request for rate case expenses?

A. It requested $260,000 per year for rate case expenses which is a two-year amortization for a total of $520,000.

Q. Are you analyzing the amount of rate case expenses or only the amortization period?

A. Staff will review the appropriate amount of these expenses. I use the Company's figures for illustration of the impacts of changing the amortization period.

Q. What is the key issue for consideration here?

A. OG&E has requested a formula rate plan. If OG&E is placed on a formula rate plan, it will likely not have a rate case for at least five years. Even without a FRP, it did not come before the Commission for nearly six years since its last general rate case, Docket No. 10-067-U.

Q. What do you recommend for rate case expense amortization?

A. I recommend a five-year amortization, or $104,000 per year at OG&E's projected level of expenses. This is a reduction of $156,000 in OG&E's expenses. This difference is all Arkansas jurisdictional. As I noted before, the amount subject to amortization may change with the Staff analysis.

H. ***Depreciation Expense: Reject Extra Arkansas Depreciation***

Q. What issue related to depreciation are you addressing?

A. I am concerned with the amortization of the accumulated depreciation differential between Arkansas and Oklahoma. 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."

I requested information in AG DR 2-43, which demonstrated that Arkansas adopted lower depreciation rates than Oklahoma in Docket No. 10-067-U. This was thus a conscious decision, not some type of oversight. Essentially, OG&E wants to negate the APSC's decision by clawing back higher depreciation rates over ten years.

I recommend that the Commission reject this portion of OG&E's rate increase, which does not improve safety and reliability but simply puts cash flow in the shareholders' pockets, to maintain the integrity of its jurisdiction.

I. ***Working Capital Assets***

Q. What issues do you raise regarding working capital assets and current and accrued liabilities?

A. In addition to the prepayments for D&O insurance discussed above ($275,948), I have two other adjustments. The total of my three adjustments is $10,057,746 (total company).

Q. What is the first adjustment?

A I recommend that Retail AFUDC on a transmission project ($7,531,483) should not be in rate base as a working capital asset, even though it may be a regulatory asset. This AFUDC is (or will be) in retail rate base earning a return on the unrecovered balance. It is double-dipping to recover a second return here.

Q. What is the second adjustment?

A I remove $2,250,315 of Miscellaneous Current and Accrued Assets in Account 174. OG&E has removed all of these assets for the first nine months but capped the amount removed in April, May, and June at the March, 2016 level, even though the total amount of those assets was increasing.

I believe this is simply a mistake, because both the underlying assets and the amounts removed were held constant in the original MFR filing from March-June. I believe that the correct treatment would be to remove all of the assets in all of the months, given that virtually all of those assets are described on its spreadsheet workpaper tab WP B 4-3 and should be increasing if the total is increasing.

Q. Are there other questionable assets?

A. Yes, there are three regulatory assets included related to flow-through income taxes from pre-1981 tax returns that should not earn a return (AFUDC recoverable in future rates, which is actually a tax item, and Federal and State flow-through income taxes, totaling $63,804,000) because OG&E never spent money in advance. However, OG&E has also included offsetting amounts of ADIT for these three assets (even though OG&E never paid taxes for them). While the appropriate accounting should leave these items out of both WCA and ADIT, the change is not material relative to leaving them in both places.

J. *Revenue Conversion Factor*

Q. What is the issue regarding the Revenue Conversion Factor?

A. OG&E does not include the Domestic Production Activities Deduction (DPAD, otherwise known as the Manufacturer's Tax Deduction) in that factor.

Q. What is the DPAD?

A. It is an extra deduction of 9% income from manufacturing activities. The generation of electricity is a manufacturing activity. Transmission and distribution are not considered manufacturing.

Q. Will you explain further?

A. OG&E includes the DPAD in calculating its taxes at current rates, but does not include additional DPAD deductions arising from additional revenue at proposed rates. I reviewed OG&E's DPAD calculations provided in AG DR 9-5. I conclude that with higher revenues at proposed rates and with all else equal, the DPAD deduction would be higher. I, therefore, include it in the revenue conversion factor (based on 39.16% generation from AG DR 9-5), in the table below.

Table 22: Revenue Conversion Factor with DPAD

(1) Line No.		(2) Description	(3) Total	(4) Commercial	(5) Industrial	(6) Public Authority	(7) Residential
1		Arkansas Corporate Tax Rate	6.50%	6.50%	6.50%	6.50%	6.50%
2		Federal Corporate Tax Rate	35%	35%	35%	35%	35%
		Percentage of Production Revenue	39.16%	39.16%	39.16%	39.16%	39.16%
		Domestic Production Activities Deduction	9%	9%	9%	9%	9%
		PDAF reduction to corporate tax	1.23%	1.23%	1.23%	1.23%	1.23%
3		Composite Tax Rate (1)	0.379950	0.379950	0.379950	0.379950	0.379950
4		Uncollectible Accounts Ratio (b)	0.002265	0.001636	0.000127	0.000114	0.005266
5		Forfeited Discounts Ratio (b)			no late payment revenues in Arkansas		
6		Revenue Conversion Factor (2) (A)	1.616434	1.615416	1.612978	1.612957	1.621311
	(1)	Composite Tax Rate = $L_1 * .65 + L_2$					
	(2)	Revenue Conversion Factor* = $1 / ((1-L_3)*(1-L_4+L_5))$					

The effective federal tax rate is reduced to 33.77%, so that the revenue conversion factor (total company) is reduced from 1.649149 to 1.616434, a reduction of 0.032715. This means that for every million dollars of income deficiency, the rate increase is reduced by $32,715.

K. *Jurisdictional and Class Allocation*

Q. Do you have any issues related to jurisdictional allocation?

A. I have two issues.

First, the Supervised O&M allocator (for A&G and general plant) needs to be modified because it erroneously includes amortization of Arkansas regulatory assets incurred in the past, which do not constitute "supervised O&M" costs.

Second, Accounts 142 (accounts receivable) and 173 (accrued utility revenue from customers) are being inappropriately allocated both to jurisdictions and to customer classes.

In both of these areas, the class allocation is also changed. I will provide my recommendation on class allocation to AG Witness Dr. David Dismukes for his use.

1. Supervised O&M Factor

Q. Why do you have a concern with the supervised O&M Factor?

A. The supervised O&M factor is supposed to represent direct O&M expenses incurred by OG&E which can be used to allocate administrative and general expenses and general plant costs. Costs such as transmission wheeling, fuel and purchased power, rents, depreciation and amortization, and uncollectible accounts expenses are (correctly) left out as not requiring administration.

However, in what seems to be an error, OG&E has included amortization of its Smart Grid costs to Accounts 586 and 909 in the supervised O&M factor, even though all other depreciation and amortization is not included and these costs do not represent any costs that need to be "supervised." Furthermore, similar Oklahoma regulatory assets are not included. The inclusion of the amortization of these regulatory assets in Arkansas alone overstates the Arkansas allocation of A&G and general plant costs.

Q. Will you compare OG&E's allocation to Arkansas under its allocation factor with the allocation to Arkansas excluding amortization of Smart Grid costs?

A. The table below shows the effect of changing the supervised O&M allocation factor to remove amortization of smart grid costs, based on OG&E's cost of service model.

Table 23: Effect of Removing Smart Meter Amortization from Supervised O&M Allocator

	OG&E	AG
Supervised O&M allocator	9.369%	9.151%
Revenue deficiency[137]	$16,513,653	$16,201,306

In other words, just making this one change reduces the requested rate increase by about $312,000 or 0.4%.

2. Allocation of Accounts Receivable and Unbilled Revenue

Q. What is the issue with allocation of this rate base?

A. These items are allocated for purpose of jurisdictional and class allocation based solely on base rate revenues without including revenues from the fuel adjustment clause and other allocation factors, using OG&E's REVASSET allocation factor.

However, as OG&E agrees (in the response to AG DR 7-01a), accounts receivable and unbilled revenues include not only base rate revenues but fuel adjustment clause revenues and all other revenues.

[137] Using OG&E's case for illustration.

Therefore the allocation factor used by OG&E is inaccurate and does not reflect cost causation.

Q. What do you recommend?

A. I recommend using booked revenue (excluding unbilled and other operating revenue) to perform the analysis. I use booked revenue because OG&E did not make all of the adjustments to its Oklahoma jurisdiction that were made to Arkansas (growth, weather, etc.).

Q. What is the effect?

A. As shown in Exhibit WM-7, Arkansas jurisdictional rate base is reduced by $124,000. Because the ECR is a larger portion of total revenue for the larger classes than for residential, general service, and lighting, there is a reduction in residential class rate base of $582,000; an increase of $831,000 for the power and light class, with other classes sharing a decrease of $249,000.

Q. Do you change the REVASSETS factor where it is used elsewhere?

A. No. Where it is used for economic development costs in Account 912, it is appropriate to use base rates, not total rates including riders, because economic development activities reduce the amount of and time between base rate increases.

IV. The Commission Should Reject OG&E's Proposed Residential Demand Charge

Q. What is a demand charge?

A. A demand charge is a charge based on the maximum use of the customer in a very narrow period within a month, a 15-minute period in the case of OG&E.

Q. How is OG&E proposing to include demand charges in residential rates?

A. OG&E is proposing a default residential rate with a $1/kW-month demand charge. It appears that such a rate design would then eventually be increased (as OG&E proposed a $2.75/kW demand charge in Oklahoma, which was rejected).

Q. Will you provide some historical perspective on demand charges?

A. Demand charges were invented in the 1890s because all that a meter could measure was the customer's non-coincident peak demand. Industry analysts, without today's computer technology that enables better analysis, simply thought that customer peaks had something to do with system-wide phenomena.

Demand charges have been made obsolete in large part by time-of-use energy rates. But utilities continue to support them because they create revenue stability – even at the expense of efficient energy use. And there is an almost ideological belief, presented as fact by many utilities, that a cost related to system demand in some way should be charged to customers based on the customer's demand even though the nexus between customer demand and system demand is not clear at all, particularly for the residential class. Thus, demand charges have persisted despite technological obsolescence. But they should not be expanded to residential customers.

It is ironic that smart meters are now being used by utilities like OG&E to promote demand charges for residential customers. Using a smart meter to deliver a residential demand charge instead of a time-of-use rate is like using a sophisticated video camera to take grainy snapshots.

Q. Does OG&E believe demand charges are cost-based?

A. Yes. The testimony of Mr. Wai states that the "change to the customer charge and the addition of a kW demand charge will more accurately reflect the fixed cost of providing electric service to a customer."[138]

Q. Did Mr. Wai do any analysis or present any evidence to support that conclusion?

A. No. He simply assumed that his conclusion was correct and that it is appropriate as a general rule to collect demand costs through charges based on the maximum demand of individual residential customers.[139]

Q. What analysis is appropriate to determine whether demand charges are reasonable and cost-based for specific sets of residential customers?

A. The analysis involves a review of the coincidence of individual customers' own maximum demand with the demands used to allocate costs to customer classes (in the case of OG&E, 4 coincident peaks (4CP) for transmission and generation and Class Peak for distribution), as well as a review of whether the customer's own Non-Coincident Peak demand (NCP) which is the basis of a demand charge, when combined with energy in the relevant time period, explains the customer's Class Peak or 4CP demand.

Q. How does one determine the coincidence of a Customer's NCP with other measures of demand?

A. Coincidence is related to the concept of load diversity. The coincidence of the sum of the customers' NCP demand is calculated by taking the other measure of demand being analyzed (for example 4CP for generation and transmission and Class Peak for distribution) divided by the sum of the customer NCP demand. The sum of the customer NCP demands will always be larger than the more diversified demands at 4CP or Class Peak. So the coincidence factor

[138] Direct Testimony of William Wai, p. 8.
[139] *Id.*, pp. 5-6.

is always less than one. The lower the coincidence factor, the worse the sum of customer NCPs (and thus a demand charge) will be in actually matching up with the demand-related costs that the utility is proposing to collect through NCP demand.

Q. What must be considered to determine whether a demand charge is reasonably cost-based?

A. The questions when analyzing the cost basis of demand charges are (1) whether the customer NCP has a systematic bias (*i.e.*, smaller or lower load factor customers have a lower coincidence than larger or higher load factor customers), (2) whether there are large amounts of variation in the coincidence among customers of the same size (so that the coincidence is so variable that it cannot be used to establish a demand charge without harming large numbers of customers by charging them rates that are not cost-based), and (3) whether the 4CP and Class Peak demand costs can be better predicted by energy use in a relevant time period than by maximum customer NCP demand in the same time period. To the extent that energy use is a better predictor of Class Peak or 4CP than maximum NCP demand, a demand charge is a less accurate and cruder method of setting rates than an energy charge. The third question is answered by use of regression equations.

Q. Did you conduct any of this analysis for OG&E's residential and small general service classes to determine whether its proposed demand charges were cost based?

A. I was unable to do so, because OG&E made no data available to allow such analysis to be done. I asked OG&E a series of data requests to obtain the information necessary to compare individual customers' NCP demand (the basis for demand charges) with those same customers' Class Peak demand (used to allocate distribution costs) and System Peak demand (used to allocate generation and transmission costs).

In response to AG DR 1-1, a data request that I have submitted to a number of utilities in the past to obtain information relevant to the analysis of both residential load characteristics by size of customers and residential demand charges, OG&E indicated that it did not have the data to enable such an analysis to be done.

OG&E also stated: "OG&E did not perform any analysis of residential billing demand to coincident peak demand and class non-coincident peak demand."[140] Based on the results of a phone conference between representatives of the Attorney General and OG&E, it appears that the reason why OG&E does not have the ability to do such analysis is because of the way in which it structures its smart meter data. It keeps the maximum demand (which it wants to use for billing) in files with other billing data. But the data on which to calculate the Class Peak or the System Peak is stored in a different file that is not linked with the billing data in any routine way and would require significant programming to link it. In other words, unlike many other utilities, OG&E has no ability to disaggregate any kind of load research to the individual customer level.

OG&E stated that it made these calculations for the residential class as a whole in MFR Schedules G-5.1.4, but never made these calculations for individual customers or for any of the specific groups of residential and small commercial customers that Mr. Wai analyzed in his testimony.[141]

OG&E also stated that it does not have any information "related to any utilities that analyze the coincidence of residential customer billing demand with system peak demand and distribution class peak demand by size of

[140] AG DR 6-1.
[141] AG DR 6-4, 6-5, 6-6 (residential) and 6-7, 6-9, and 6-10 (general service).

customer, load factor of customer."[142] Thus it was unaware of whether any other research had been done related to any other utility to analyze these issues.

Q. Have you, personally, done research on the cost basis of demand charges?

A. Yes, for three utilities, El Paso Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company. I am attaching information on these three companies, the first two from testimony and the third from a conference presentation, as Exhibits WM-8, WM-9, and WM-10.

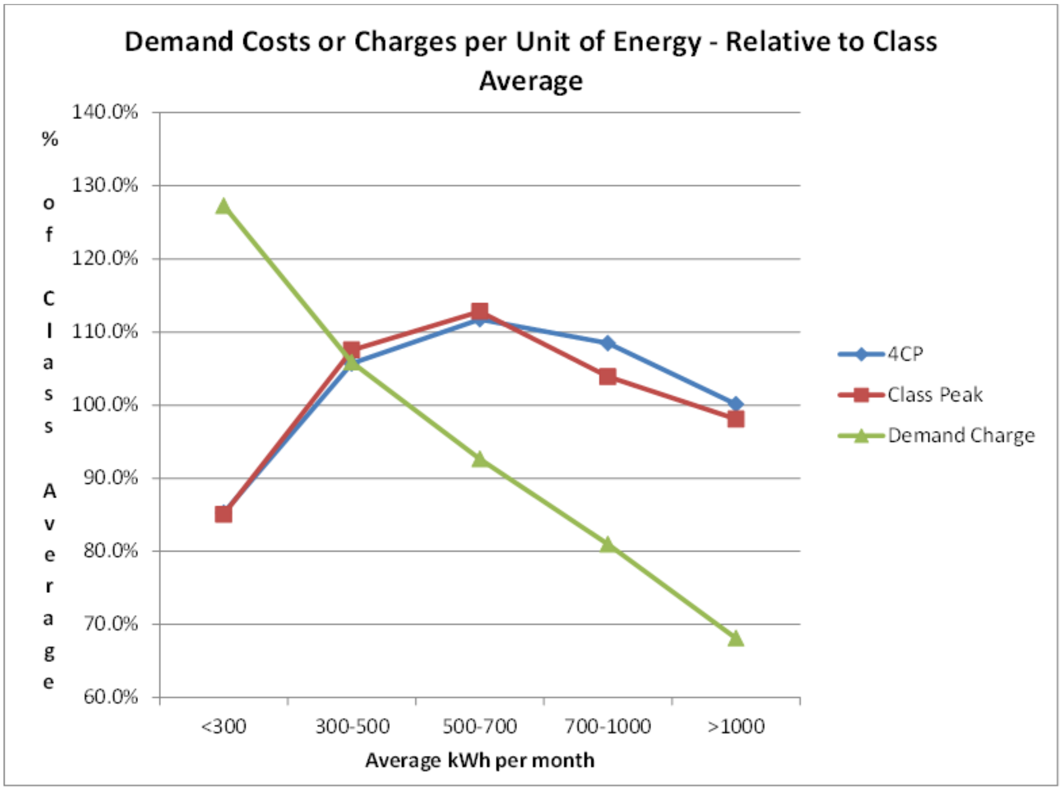
Q. What were your general findings?

A. For all three utilities, I found that demand charges are systematically biased against smaller customers. In other words, small customers have the same or better load factors than large customers measured against Class Peak and System Peak, but they have lower load factors and thus lower coincidence when measured against the customers' own maximum demands.

The result is large intraclass subsidies. These subsidies are as exemplified on page 49 of Exhibit WM-9 (SDG&E), which is reproduced here.

[142] AG DR 6-3.

Figure 4: San Diego Gas and Electric Company Demand Costs and Charges, Relative to Class Average, by Size of Residential Customer



The smallest customers on the SDG&E system use 20% less peak demand per unit of energy (have better load factors relative to system and class peak) than the average but would pay 36% higher demand charges per unit of energy. The largest customers use approximately the system average peak demand per unit of energy (have an average load factor), but would pay 31% lower demand charges per unit of energy than the average. This is an intraclass subsidy.

Q. What is your conclusion?

A. OG&E has not met its burden of proof that residential demand charges are cost-based. The Company made the assertion that residential demand charges were cost-based, but it is unable to produce any data on its own customers that would enable the Attorney General to test the soundness of its conclusions. It also has never reviewed information related to any other utilities on the relationship between demand charges and demand costs by size of customer, so it has no information at all.

By contrast, I have conducted analysis that gives me some of that information from three other utilities. My previous analysis shows that in each case demand charges are not cost-based and would systematically over-collect costs from small customers.

Given OG&E's complete lack of relevant information, its inability to provide data to me to enable me to analyze its system, and the previous work that I have done on other utilities, I conclude that it would be unreasonable for the Commission to adopt any demand charge for OG&E based on the OG&E's showing in this case.

Q. In addition to your comments on the cost basis of demand charges, will you generally discuss customer reactions to demand charges?

A. Customers tend to mistrust demand charges. For example, a recent focus group study in Ontario, Canada, where time-of-use (TOU) rates have been in place for several years and customers are thus fairly sophisticated, suggests that residential customers do not understand demand charges and believe that such charges are demanding perfection in their conservation efforts. The Ontario Energy Board conducted an analysis with residential focus groups that raised concerns about maximum monthly usage charges (another term for demand charges) in addition to TOU rates that Ontario customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.

> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.[143]

Q. Can you make other specific points regarding the effect of demand charges on customer behavior and energy efficiency?

A. There are a number of reasons why residential demand charges raise concerns.

1. They blunt incentives to conserve – even during peak periods - once a maximum demand is hit. A demand charge is essentially another fixed charge, like a customer charge, which is difficult for a customer to avoid.

2. Customers can only avoid demand charges by keeping track of random events which have no intrinsic value to anyone and responding perfectly to them day after day. Customers do not want to be rate computers, but to reduce their demand charge some may need to have the following scenario in mind **every winter morning**: "My coffee-maker is running, and it's chilly so my furnace fan is running. That means I shouldn't turn on the toaster and the hair dryer at the same time at 7 am or I could get a higher demand charge. I need to wait 15 minutes to use that toaster." Another example is, "I could get a higher demand charge by running the washer and dryer at the same time (along with other equipment). So I need to inconvenience myself and take more time to wash and dry multiple loads of laundry." This kind of price signal is totally disconnected from either causation of or avoidance of utility costs. It is also a waste of the very limited amount of brainpower that most people

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[143] The Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups: Final Report, October 9, 2013, p. 9.

want to spend on their electric rates. So customers are likely to eventually make expensive mistakes and give up trying – defeating the purported purpose of the demand charge.

3. Significant demand charges would give customers who are connected to gas strong incentives to get rid of electric stoves and ovens and electric dryers. Before bringing in a residential demand charge, an electric utility should have the obligation to inform customers that an electric stove is one of the worst things to own if there's a demand charge – either non-coincident or peak period only, because the oven plus the air conditioner will trigger the charge. Since OG&E is in competition with an independent gas utility (Arkansas Oklahoma Gas Corporation - AOG), if demand charges were imposed and later increased from the levels proposed by OG&E in this case, OG&E would be handing AOG an excellent marketing plan to poach load from the electric utility because gas would be far more cost-effective for these end uses because it avoids demand charges.

4. Residential demand charges can have bizarre impacts on cost-effectiveness of energy efficiency to customers – which are not necessarily the same as cost-effectiveness of those efficiency measures to the utility or society. Getting a more efficient air conditioner (or even a smaller one of the same efficiency) can reduce a demand charge, but weatherizing one's house so an existing air conditioner runs less frequently but produces the same number of kilowatts when it turns on, will not reduce the customer's bills nearly as much, even if it has similar effects on <u>system</u> peak demand, because the demand charge won't change.

Q. What is your conclusion on demand charges?

A. OG&E has no information to demonstrate that its proposed residential demand charge is cost-based and has thus not borne its burden of proof on that issue in light of contrary data from other utilities. Moreover, demand charges have significant issues related to customer acceptance and significant (and perverse) ramifications for customer behavior, fuel substitution between gas and electricity, and energy efficiency policy. The Commission should reject OG&E's proposed demand charge.

Q. Does this conclude your testimony?

A. Yes it does.

CERTIFICATE OF SERVICE

I, Shawn McMurray, hereby certify that on January 31, 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