COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS CORPORATION FOR FOR A GENERAL RATE ADJUSTMENT	))	CASE NO. 2015-00343

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
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Certificate of Service and Filing

Counsel certifies that: (a) the foregoing is a true and accurate copy of the same document being filed in paper medium; (b) pursuant to 807 KAR 5:001, Section 8(7)(c), there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and (c) the original and copy in paper medium is being filed with the Commission.

I further certify that in accordance with 807 KAR 5:001 § 4 (8), the foregoing is being contemporaneously provided via electronic mail to:

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Assistant Attorney General

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE: APPLICATION OF ATMOS ENERGY	**)**	
CORPORATION FOR AN	**)**	**CASE NO. 2015-00343**
ADJUSTMENT OF RATES AND	**)**	
TARIFF MODIFICATIONS	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 2016

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

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BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS**	**))))**	**CASE NO. 2015-00343**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned both a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in Theology from Luther Rice University. I am a Certified Public Accountant, with a practice license, Certified Management Accountant, and Chartered Global Management Accountant. I am a member of numerous professional organizations.

I have been an active participant in the utility industry for more than thirty years, both as an employee and as a consultant. Since 1986, I have been a consultant with J. Kennedy and Associates, Inc., providing services to state government agencies and consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, tax, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on hundreds of occasions. I have been actively involved and testified on dozens of occasions on specific income tax and normalization issues. I have worked, on behalf of utility customers and together with utility counsel, to draft requests for Internal Revenue Service ("IRS") Private Letter Rulings ("PLRs") on normalization issues. I have met with, on behalf of utility customers, Senior Technician Reviewers in the IRS Office of the Associate Chief Counsel (Passthroughs and Special Industries), in conferences of right. I have developed and presented comments before the Treasury Department and the IRS, on behalf of utility customers, regarding proposed rulemakings and income tax normalization requirements. In addition, I have testified in numerous proceedings before the Kentucky Public Service Commission ("Commission"), including numerous base, fuel adjustment clause, and environmental surcharge ratemaking proceedings involving Big Rivers Electric Corporation, East Kentucky Power Cooperative, Kentucky Power Company, Kentucky Utilities Company, and Louisville Gas and Electric Company. Further, I have testified before the Georgia Public Service Commission in multiple Atmos base rate proceedings.[1]

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your testimony?

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

A. The purpose of my testimony is to address and make recommendations on specific issues that affect the Company's requested base rate increase in this proceeding and to quantify the effects of AG witness Mr. Richard Baudino's recommendations.

Q. Please summarize your testimony.

A. The AG recommends a base rate *reduction* of $7,849,968 compared to the Company's request for a base rate increase of $3,213,606, as revised. The following table provides a summary of the revenue requirement effects of the AG's recommendations.

Atmos Energy Corporation - Kentucky Division
Summary of Attorney General Recommendations
KPSC Case No. 2015-00343
Test Year Ended May 31, 2017

Atmos As-Filed Requested Increase	$	3,307,688
Less: Reduction Related to Company Revision to Reflect Bonus Depreciation		(94,082)
Atmos Revised Requested Increase	$	3,213,606
Effects on Increase of AG Rate Base Recommendations		
Remove Forecast 10% Escalation on Capital Additions for Kentucky Non-PRP	$	(50,680)
Remove Account 190 ADIT Not Associated With Cost of Service		(204,286)
Include Temporary Differences Associated With 190 ADIT Included in Cost of Service		(686,038)
Remove NOL ADIT in Acct 190		(3,493,884)
Reflect Zero Balance for Cash Working Capital		(378,460)
Remove Rate Case Expense Regulatory Asset		(41,798)
Extend Amortization Period for PLR Regulatory Asset to 3 Years		1,309
Effects on Increase of AG Operating Income Recommendations		
Remove Amortization Expense for Rate Case Expense Regulatory Asset		(234,455)
Extend Amortization Period for PLR Regulatory Asset to 3 Years		(22,022)
Adjust Depreciation Expense to Remove Forecast 10% Escalation on Capital Additions		(19,412)
Include AEC Commitment and Banking Fees in Operating Income		119,560
Effects on Increase of AG Rate of Return Recommendations		
Reflect Adjusted Capital Structure		(1,153,299)
Reduce Short Term Debt Rate by Removing AEC Commitment and Banking Fees		(147,101)
Reflect Return on Equity of 9.0%		(3,830,361)
Effects of Change In Composite Allocation Factor - All Aspects of Revenue Requirement		(922,647)
Total AG Recommendations	$	(11,063,574)
AG Recommendation to Reduce Base Rates	$	(7,849,968)

I address all the rate base and operating income AG recommendations reflected on the preceding table. I also quantify the effects on the revenue requirement of the rate of return recommendations addressed by Mr. Baudino. In addition, I address the AG recommendation to modify the Division 002 *Shared Services* and Division 091 *Kentucky/Mid-States* composite factors, which affect rate base and operating expense allocations to the Kentucky retail jurisdiction. I have structured my testimony to sequentially address these issues.

II. RATE BASE ISSUES

Non-PRP Capital Expenditures and Plant Additions Are Overstated and Should Be Reduced

Q. Please describe the escalation rate applied by the Company for non-Pipeline Replacement Program ("PRP") capital expenditures and how this affects the rate base and depreciation expense proposed by the Company.

A. The Company used a 10% escalation rate for Kentucky rate division non-PRP capital expenditures for the months of October 2016 through May 2017, which it applied to the non-PRP "budget" capital expenditures for the months of October 2015 through May 2016.[2]

Q. Is this escalation rate reasonable?

A. No. It is three to five times greater than projected inflation of approximately 2%-3%. It also is inconsistent with the Company's projected growth in O&M expense, which is relatively flat in the test year compared to the base period.

Q. What is your recommendation?

A. I recommend that the Commission reject the escalation rate proposed by the Company and instead reflect the same level of capital expenditures for these months in the test year as were reflected in the Company's most recent capital expenditure budget.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is a reduction in the revenue requirement of $70,092, consisting of $50,680 for the grossed-up return and $19,412 for depreciation.[3]

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[2] Refer to response to Staff 1-59 WP ATT26. I have not attached a copy of this response as an exhibit due to its magnitude.

[3] I utilized the Company's response to Staff 1-59 WP ATT26 to calculate the reduction in rate base by changing the escalation factor in the spreadsheet to 1.00 from 1.10. I then multiplied this reduction in rate base times the Company's proposed grossed-up cost of capital. I provide a summary of the change in rate base on my Exhibit___(LK-2) and the calculation of the change in depreciation expense on my Exhibit___(LK-3).

<u>The Accumulated Deferred Income Taxes and Temporary Differences (Liabilities) Subtracted from Rate Base Are Understated and Should Be Increased</u>

Q. Please provide a description of accumulated deferred income taxes and how they are recognized for ratemaking purposes.

A. There are both accumulated deferred income tax liabilities ("DTLs") and accumulated deferred income tax assets ("DTAs"). DTLs generally are subtracted from rate base because they represent cost-free capital to the utility and DTAs generally are added to rate base because they must be financed by the utility, although there are exceptions to this general ratemaking practice if the related costs are not included in the revenue requirement.

If the Company improperly adds certain DTAs to rate base, then the net accumulated deferred income taxes subtracted from rate base are understated and rate base and the revenue requirement are overstated. Similarly, if the Company correctly adds certain other DTAs to rate base, but fails to subtract the related temporary differences, or liabilities, that gave rise to the DTAs, then the rate base and revenue requirement are overstated.

DTLs represent deferred income tax amounts that will be paid to federal and state governments by the utility in future years and reflect the accumulation of deferred income tax expense, one of two components in the calculation of income tax expense. These amounts typically are recorded in accounts 281, 282, and 283 pursuant to the

Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

DTLs represent the tax effects of temporary, or timing, differences where income is deferred or deductions are accelerated on the income tax returns compared to the recognition of income and expenses for accounting purposes. In this case, the temporary difference reduces *current* income tax expense, but is offset by an equivalent *deferred* income tax expense. The deferred tax expense related to each temporary difference is accumulated as a separately identified DTL. For example, a utility will deduct accelerated or bonus tax depreciation on its tax return, but will record straight line depreciation for accounting purposes. The temporary difference for the excess of the tax depreciation over the accounting depreciation is a deduction to taxable income and reduces current income tax expense. This same temporary difference is multiplied times the federal and state income tax rates to calculate the deferred tax expense and then added to the DTL. At some point in the future, the tax depreciation for those same assets will be less than the accounting depreciation, the deferred tax expense will be negative, and the DTL will reverse, and ultimately decline to zero when the assets are fully depreciated for both tax and accounting purposes.

DTAs represent prepaid income tax amounts that will be refunded by the federal and state governments to the utility in future years. These amounts are typically recorded in account 190 pursuant to the FERC USOA. DTAs represent the tax effects of temporary, or timing, differences where income is accelerated and deductions are delayed on the income tax returns compared to the recognition of income and expenses for accounting purposes. In other words, the temporary differences for DTAs are the opposite of the temporary differences for DTLs. In this case, the temporary difference increases current income tax expense, but is offset by an equivalent reduction in deferred tax expense, and the deferred tax expense related to each temporary difference is accumulated as a separately identified DTA. At some point in the future, the specific temporary differences giving rise to the DTAs will reverse, and ultimately, the DTAs will decline to zero when the income or deduction is fully recognized for tax and accounting purposes.

It should be noted that many temporary differences are recurring, i.e., they are deferred in one month or year, then are reversed the following month or year, and then are followed by another deferral in the next month or year and another reversal.

Q. Have you reviewed the DTL and DTA amounts that the Company included in rate base?

A. Yes. The Company included the entirety of the DTAs and DTLs projected for the test year in accounts 190, 281, 282, and 283 originating in all divisions, except for the DTL related to the gas over/under recovery and the DTA related to the net operating loss

("NOL") "attributable to the Company's unregulated business."[4]

The Company provided DTAs and DTLs by temporary difference and account for each division in response to Staff discovery.[5] I reviewed this detail and identified numerous DTAs that should not be included in rate base for Division 002 *Shared Services* and Division 091 *Kentucky/Mid States*. I also identified numerous DTAs that should be included in rate base, but only if the related temporary difference is subtracted from rate base, for Divisions 002 and 091; otherwise they should not be included in rate base.

The Division 002 DTA amounts that were improperly included in rate base are due to the following temporary differences: Management Incentive Plan ("MIP") and Variable Pay Plan ("VPP") expense, self-insurance expense (accrual for reserve accounting), restricted stock grant plan expense, Rabbi Trust, restricted stock – MIP expense, Director's stock awards expense, charitable contribution expense carryover, and VA charitable contributions expense.[6,7]

The Division 091 DTA amounts that were improperly included in rate base are

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[4] Waller Direct at 16.

[5] Attachment 2 to the response to Staff 1-59, which was updated in response to Staff 2-21 to reflect the effects of the extension of bonus depreciation enacted in December 2015.

[6] The Company also improperly included the DTA for the net operating loss ("NOL") temporary difference. I separately address this DTA in the following section of my testimony due to its significance and the Company's claim that it must be included in rate base to avoid a normalization violation.

[7] The Company described the underlying temporary differences giving rise to these DTAs in response to AG 2-13. I have attached a copy of this response as my Exhibit___(LK-4).

due to the following temporary differences: MIP and VPP expense, charitable contribution expense carryover, and regulatory asset expense.

Q. Why should the Commission exclude these DTAs from rate base?

A. In general, these DTAs are related to costs that are not recovered through the ratemaking process. None of the costs giving rise to these DTAs are included in operating expenses or subtracted from rate base in the determination of the revenue requirement. Thus, neither the DTAs should be added to rate base nor the temporary differences subtracted from rate base.

In addition, the DTAs related to the VA charitable contributions (even though it was a DTL recorded in account 190) in its former Virginia jurisdiction and the DTA related to a regulatory asset expense in its Tennessee jurisdiction[8] are not a cost of the Kentucky rate division. Instead, they should have been directly assigned to the Virginia and Tennessee rate divisions.

Further, the DTA related to the VA charitable contributions is due to a below the line expense and should be excluded from rate base for that reason as well.[9]

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[8] Refer to the Company's responses to AG 2-13 and AG 2-14, respectively, which I have attached as my Exhibit___(LK-4) and Exhibit___(LK-5), respectively.

[9] *Id.*

Q. Did you identify a second category of errors?

A. Yes. For several other DTAs, the Company failed to subtract from rate base the related temporary differences that gave rise to the DTAs. This violates the basic ratemaking principle of matching benefits and costs and fails to provide customers a rate of return on the expenses recovered in rates, but retained by the utility as a liability until paid at a later date. This is not a problem with the DTAs, but rather, is due to the Company's failure to subtract the temporary differences from rate base.

The DTAs do not exist in a vacuum. The only reason the utility has the DTA is because the accounting expense is accrued, but not recognized as a deduction for income tax purposes until it actually is paid. The utility accrues a liability to pay the expenses recovered from customers, which is released when the liability is paid. The deduction for income tax purposes also is taken when the liability is paid and the DTA is reversed.

For these DTAs, the correct ratemaking is to subtract the liabilities, or temporary differences, from rate base and to add, or include, the DTAs in rate base. If the liabilities are not subtracted from rate base, then DTAs also should be excluded, along with the other DTAs in the first category that I described.

The DTAs and related temporary differences in this second category include SEBP expense, Rabbi Trust, and Director's stock awards expense.[10]

[10] The Company described the underlying temporary differences giving rise to these DTAs in response to AG 2-14. I have attached a copy of this response as my Exhibit___(LK-5).

Q. Does the Company agree that the DTAs in the first category should be excluded from rate base?

A. Yes. The Company stated in response to discovery that it would not oppose adjustments to exclude these DTA amounts from rate base.[11]

Q. Does the Company agree that the DTAs in the second category should be excluded from rate base or that the related temporary differences be subtracted from rate base?

A. No. The Company claims that these DTAs should be included in rate base because the expense is included in operating income.[12] Although the expenses are included in the revenue requirement, that is not enough to justify the addition of these DTAs in rate base, as I previously explained. The liabilities resulting from the delayed payment of the expenses must be subtracted from rate base; otherwise the DTAs should be excluded from rate base.

Q. Have you quantified the effects on the revenue requirement of excluding the DTAs in the first category from rate base?

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[11] *Id.*
[12] *Id.*

A. Yes. The effects for each DTA and in total are summarized on the following table.[13]

Atmos Energy Corporation - Kentucky Division
AG Recommendation to Exclude Certain DTAs from Rate Base
KPSC Case No. 2015-00343
Test Year Ended May 31, 2017
$

See Responses to AG 2-13 and 2-14

Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
MIP/VPP Accrual	1,253,998	5.26%	65,930	11.89%	7,836
Self Insurance Adjustment	4,576,432	5.26%	240,610	11.89%	28,597
Restricted Stock Grant Plan	7,385,565	5.26%	388,303	11.89%	46,150
Restricted Stock MIP	9,513,920	5.26%	500,203	11.89%	59,450
Charitable Contribution Carryover	10,525,877	5.26%	553,407	11.89%	65,773
VA Charitable Contribution Carryover	(6,968,891)	5.26%	(366,396)	11.89%	(43,546)
Total Division 002	26,286,901		1,382,057		164,259

Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
MIP/VPP Accrual	141,947	49.09%	69,682	11.89%	8,282
Charitable Contribution Carryover	163,960	49.09%	80,489	11.89%	9,566
Reg Asset Benefit Accrual	380,148	49.09%	186,616	11.89%	22,180
Total Division 091	686,055		336,788		40,027

Total First Category Reduction to Revenue Requirement Related to Account 190 ADIT	$ 204,286

Q. Have you quantified the effects on the revenue requirement of subtracting the temporary differences for the DTAs in the second category from rate base?

A. Yes. The effects for each temporary difference and in total are summarized in the following table.[14]

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[13] The detailed calculations are shown on my Exhibit____(LK-6). On my exhibit, the DTA amounts for Division 002 are calculated for the Kentucky rate division using the Division 002 composite factor. The rate base effects of the temporary differences related to the DTA amounts for Division 091 are allocated to the Kentucky rate division using the Division 091 composite factor. I applied the Company's proposed grossed-up cost of capital to the Kentucky rate division allocation to determine the revenue requirement.

[14] The detailed calculations are shown on my Exhibit____(LK-7). On my exhibit, the rate base effects of the temporary differences related to the DTAs for Division 002 are allocated to the Kentucky rate division using the Division 002 composite factor. The rate base effects of the temporary differences related to the DTAs for Division 091 are allocated to the Kentucky rate division using the Division 091 composite factor. I applied the Company's

Atmos Energy Corporation - Kentucky Division
AG Recommendation to Subtract Temporary Difference Associated with Certain DTAs
KPSC Case No. 2015-00343
Test Year Ended May 31, 2017
$

See Responses to AG 2-13 and 2-14

Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	Temp Diff Revenue Req KY Division
SEBP Adjustment	24,316,653	62,510,676	5.26%	3,286,554	11.89%	390,610
Rabbi Trust	1,534,495	3,944,717	5.26%	207,397	11.89%	24,649
Director's Stock Awards	4,119,248	10,589,326	5.26%	556,743	11.89%	66,169
Total Division 002	29,970,396	77,044,720		4,050,694		481,428

Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
SEBP Adjustment	1,364,197	3,506,933	49.09%	1,721,570	11.89%	204,610

Total Second Category Reduction to Revenue Requirement Related to Account 190 ADIT $ 686,038

The DTA Due to the NOL Temporary Difference Should Be Excluded from Rate Base

Q. Please describe the DTA due to the NOL carryforward temporary difference.

A. The Company allocated $29,397,220 of the Atmos Energy Corp. ("AEC") DTA due to the NOL carryforward (DTA – NOL) temporary difference to the Kentucky jurisdiction and added it to rate base. That allocation increases the Kentucky jurisdictional rate base and offsets the DTL due to accelerated and bonus tax depreciation that otherwise would be subtracted from rate base. This DTA increases the Company's revenue requirement by $3,493,884.[15]

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proposed grossed-up cost of capital to the Kentucky rate division allocation to determine the revenue requirement.

[15] I show the calculation of the amounts included in the Company's filing allocated to Kentucky and the calculation of the revenue requirement effect on my Exhibit___(LK-8).

Q. Please describe the origination of the DTA – NOL.

A. The AEC DTA – NOL is calculated by AEC based on its actual consolidated taxable income, which it separates into regulated utility taxable income and unregulated affiliate taxable income. AEC utilizes a fiscal year ending September 30 for financial reporting and for income tax purposes. For each fiscal year, AEC calculates its taxable income on a consolidated basis, including both income and deductions for the regulated and unregulated segments and determines whether there is a taxable loss. If there is a loss, AEC can carry it back against taxable income in the three prior fiscal years. If there is any remaining loss, then it can carryforward that loss and apply it against taxable income in future fiscal years. The DTAs, both federal and state, are calculated by multiplying the federal and state income tax rates times the NOL carryforward temporary difference. In future years, the DTAs are reduced as the carryforwards are used or are increased if there are additional taxable losses.

AEC repeats this process for the regulated and unregulated segments. In recent years, the regulated utility segment has a carryforward loss, but the unregulated segment has had income in those same fiscal years. That means that AEC allocates a greater DTA – NOL to the regulated segment than actually exists on its consolidated books.

Q. Please describe how the accounting works when there is a taxable loss and carryforward, particularly the interrelationship between the current income tax expense, deferred tax expense, and the DTA – NOL.

A. In years in which there is a taxable loss that cannot be carried back, the utility credits (reduces) deferred income tax expense for the tax effect of the loss, which reduces the deferred income tax expense and total income tax expense, and defers the reduction in income tax expense through a debit (increase) to the DTA – NOL in account 190. If the next year results in another taxable loss, then this process is repeated and the DTA – NOL in account 190 grows. If, however, the next year results in taxable income, then there is a reduction in taxable income in that year by the amount of the carryforward that is used, thus reducing the current income tax expense. This is offset by an increase in deferred income tax expense and a credit (reduction) to the DTA – NOL.

Q. Did the Company correctly describe this interrelationship in its Request for PLR?

A. Yes. The Company provided a copy of its Request for PLR as Exhibit PM-1 attached to Atmos witness Mr. Pace McDonald's Direct Testimony. In that Request for PLR, the Company assumed pretax book income of $1,000, temporary differences due to accelerated tax depreciation of $2,500, a net operating loss of $1,500 ($1,000 less $2,500), no ability to carryback the loss, and an income tax rate of 35%.

In the resulting accounting entries, the Company shows $0 in current income tax expense and deferred income tax expense resulting from the temporary difference from accelerated tax depreciation of $875 ($2,500 times 35%), for a combined $875 in total income tax expense *before* consideration of the NOL. However, the loss results in a credit (reduction) to deferred income tax expense of $525 ($1,500 times 35%) and a DTA – NOL of $525, for a combined $350 in total income tax expense *after* consideration of the NOL ($875 less $525).

Q. Does that mean that combined income tax *expense* (current income tax expense and deferred income tax expense) is reduced in the year of the taxable loss?

A. Yes. The reduction of $525 in combined income tax *expense* was deferred as a DTA – NOL in account 190.

Q. Has that reduction in income tax *expense* ever been reflected in the Atmos revenue requirement?

A. No. The Commission has never reduced the income tax expense included in the Atmos revenue requirement to reflect the reduction due to a net operating loss.

Q. Can you demonstrate that?

A. Yes. The Commission uses a formula methodology to calculate combined income tax expense that is based on pretax book income before the per books interest expense, less the synchronized interest expense, times the income tax rate. In the calculation of income tax expense, the Commission does not distinguish between current income tax expense and deferred income tax expense. The Commission does not and has not reduced this combined income tax expense for the effects of any credit to deferred income tax expense for net operating loss carryforwards.

This methodology and the results can be seen on the Company's filing Schedule E in this case.[16] For the test year, the Company shows jurisdictional "operating income before income tax & interest" of $36,407,204, which ties to Schedule C-2. It then calculates "taxable income" by subtracting the "interest deduction" of $7,739,473, which is the synchronized interest based on the weighted average cost of debt times the Company's proposed jurisdictional rate base. The calculation of synchronized interest is shown on the lower part of this schedule.

In the final step, the Company calculates federal and state income tax expense by multiplying taxable income of $28,667,731 times the combined federal and state income tax rate of 38.9%. The calculated federal and state income tax expense is $11,151,747.

It should be noted that the $11,151,747 shown on Schedule E is the income tax before the proposed rate increase. The Company adds another $1,241,466 to reflect the

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[16] I have attached a copy of Schedule E as my Exhibit___(LK-9) for ease of reference.

income tax expense on its requested rate increase, and included a total of $12,393,213 in federal and state income tax expense in the revenue requirement.[17]

Q. Did the Company reflect any reduction in the income tax expense calculated in this manner for the NOL that it projects for the test year?

A. No. The Company projects that the DTA will increase by $8,076,557 in the test year compared to the base period,[18] a period of 17 months, yet it failed to reflect any portion of this amount as a reduction to the income tax expense to its revenue requirement. On a simple straight-line basis, such an NOL credit would reduce income tax expense by $5,701,099 ($8,076,557 / 17 * 12), all else equal.

The Company confirmed that it had reflected *no* reduction to the combined income tax expense included in the revenue requirement in this proceeding in response to AG discovery.[19] The Company also confirmed that it had reflected *no* reduction to the combined income tax expense included in the revenue requirement in Case No. 2013-00148 in response to AG discovery.[20]

[17] Refer to Schedule B-5F. I have attached a copy of Schedule B-5F from the Company's filing as my Exhibit___(LK-10) for ease of reference.
[18] *Id.*
[19] Refer to the Company's response to AG 2-1, a copy of which I have attached as my Exhibit___(LK-11).
[20] *Id.*

Q. If Atmos recovers income tax expense with no reduction for the effects of an NOL in the revenue requirement, then is it reasonable for customers to pay a return on the DTA – NOL when they already have paid for the expense in the revenue requirement?

A. No. The Company's proposal is grossly inequitable and would impose an unreasonable and unjustified cost on customers. Atmos already recovers its full income tax expense from customers in the revenue requirement. To the extent that the Company did not actually pay that expense due to an NOL and instead deferred the cash savings in the DTA – NOL, there is a benefit (avoided financing costs) that accrues to the Company and solely to the Company. Customers should not have to pay a carrying charge on income tax expense that they already have paid through the revenue requirement, but that the Company has been able to retain through deferred payments to the federal and state governments. The Company is economically made whole without including the DTA – NOL in the rate base.

Q. Do the normalization requirements set forth in the Internal Revenue Code of 1986 ("IRC") require that the Commission include the DTA – NOL in rate base or risk losing the DTL benefits of accelerated tax depreciation?

A. No. In addition to the IRC itself, the IRS provides guidance to taxpayers through PLRs. PLR 2014-18024 provides the most recent and most directly relevant guidance to the

Commission, including Atmos, even though this is not the PLR requested by Atmos. The Request for PLR and the PLR obtained by Atmos are fundamentally flawed and cannot be relied on because they do not accurately reflect the fact that the Commission does not and has not reduced income tax expense for the credit to deferred income tax expense resulting from the NOL.

The facts set forth in PLR 2014-18024 are identical to the facts before the Commission in this proceeding, except that the regulator in that case declined to include the DTA – NOL in rate base because it claimed that it included the entire income tax expense in the revenue requirement without reduction for the NOL. The utility disagreed with the regulator in that case and sought a PLR to buttress its arguments. However, in that PLR, the IRS decided against the utility and in favor of the Commission. The IRS determined that if the Commission did not reduce income tax expense for the NOL, then it was not required to include the DTA – NOL in rate base. Alternatively, the IRS determined that if the Commission reflected the reduction in income tax expense for the NOL, then it must include the DTA – NOL in rate base.

In short, there is no normalization violation if the Commission does not reflect the NOL in income tax expense and does not include the DTA – NOL in rate base, or if the Commission reflects the NOL in income tax expense and includes the DTA – NOL in rate base. This PLR reflects a logical outcome and is consistent with the economics of the ratemaking process that I previously described.

PLR 2014-18024 states:

> Commission has stated that, in setting rates it includes a provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates.
>
> ***
>
> Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of §1.167(I)-1 of the Income Tax regulations.

Q. Is the income tax expense included in the revenue requirement by the Commission in the Atmos rate proceedings calculated in the same manner as that described by the IRS for the other utility in PLR 2014-18024?

A. Yes. The income tax expense "in setting rates . . . includes a provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC." Such a provision allows a utility to collect amounts from "ratepayers equal to income taxes that would have been due absent the NOLC and MTCC."

It should be noted that the methodology used by the Commission incorporates the effects of all temporary differences, thus netting DTAs and DTLs, and does not specifically calculate the current income tax expense or deferred tax expense for each temporary difference. It nevertheless, through the formula methodology, includes the provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation.

Q. At the Commission's direction in Case No. 2013-00148, Atmos sought and obtained a PLR that Atmos now argues requires the Commission to include the DTA – NOL in rate base even though the Commission also includes income tax expense in the revenue requirement with no reduction for the NOL. Please respond.

A. Unfortunately, the Atmos Request for PLR includes a factual inaccuracy that renders it inapplicable and irrelevant. In its Request for PLR, Atmos incorrectly claims that the Commission's ratemaking for income tax expense is *different* than the ratemaking for the utility in PLR 2014-18024 and argues that the IRS determination in PLR 2014-

18024 was inapplicable to Atmos specifically for that reason.[21]

In its Request, Atmos states: "The type of ratemaking for the DTA claimed by the regulators in PLR 201418924 is not practiced (or even claimed to be practiced) by the regulators in Kentucky."[22] In this proceeding, when the AG asked the Company to support that critical factual claim in its Request for PLR, the Company asserted (incorrectly) that the Commission had reduced the deferred income tax expense for the NOL credit.[23] The Company stated in its response:

> In setting the provision (or tax expense) for deferred taxes in the case, the Commission in PLR 201418024 took into account the entire difference between accelerated tax and regulatory depreciation. It did not adjust the deferred tax provision for the establishment of an NOLC DTA.
>
> Unlike PLR 201418024, the provision for deferred taxes in KPSC 2013-00148 was impacted by both the entire difference between accelerated tax and regulatory depreciation AND the recording of an NOLC DTA. If the Company's NOLs had been excluded from the deferred tax provision, the Company's provision for income taxes would have been higher than [the] tax provision included in the filing.[24]

In addition, the AG asked the Company to:

> Please confirm that the KPSC reflected full income tax normalization in the income tax expense allowed in Case No. 2013-00148, meaning that it included the deferred income tax expense debit related to accelerated tax depreciation with no reduction for any deferred income tax expense credit related to and NOL. Cite to the Order and all other record evidence that supports your

[21] Exhibit PM-1 attached to Mr. McDonald's Direct Testimony.
[22] *Id.*
[23] Atmos response to AG 1-22, which I have attached as my Exhibit___(LK-12).
[24] *Id.*

response.

The Company responded:

> The Company did reflect full income tax normalization but the meaning of full income tax normalization as described in the question is incorrect. Full income tax normalization would result in a provision for income taxes which includes the debit (increase) related to accelerated tax depreciation AND a credit (decrease related to the recording of an NOL. While not specifically addressed in the order, the deferred income tax expense in KPSC Case No. 2013-00148 was calculated in this manner.[25]

The Company's assertion made in the Request for PLR and repeated in the Company's responses to AG discovery simply is incorrect. The AG subsequently asked the Company to identify where in its filing in Case No. 2013-00148 or in the Commission's Order in that proceeding and where in this proceeding there was any reduction in income tax expense for the NOL credit. In response, the Company asserted that it had been reflected, but failed to identify any such specific adjustment.[26]

This is a critical factual issue. The Company's Request for PLR had it wrong. The Company's initial responses to AG discovery had it wrong. There is no reduction in income tax expense for the NOL credit. Simply claiming that there is does not make it so.

The IRS relied on the accuracy of the Company's representation and repeated it

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[25] *Id.*
[26] Response to AG 2-1, a copy of which I have attached as my Exhibit___(LK-13).

in the PLR as follows:

> Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

The PLR itself states:

> This ruling is based on the representations submitted by the Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Thus, the critical factual error renders the Atmos PLR inapplicable and irrelevant. The Commission is not required to include the DTA – NOL in rate base to avoid a normalization violation.

Alternatively, the Commission is not required to provide the Company recovery of income tax expense without reduction for the NOL credit if it includes the DTA – NOL in rate base.

Q. Does the impact of these two alternatives vary significantly?

A. Yes. If the Commission excludes the DTA – NOL from rate base, it results in a significant reduction in the revenue requirement, but the reduction is less than the effect of eliminating or reducing the income tax expense, which the Company acknowledges is comprised solely of deferred income tax expense and the $0 in current income tax expense due to the NOL in the test year.[27]

Q. What is your recommendation?

A. I recommend that the Commission exclude the DTA – NOL from the Company's rate base. Alternatively, the Commission should reduce income tax expense to reflect the NOL credit. Either approach is consistent with the IRC normalization requirements.

<u>Cash Working Capital is Overstated and Should be Reduced to $0 in the Absence of A Valid Lead/Lag Study</u>

Q. Please describe the Company's request for a cash working capital allowance in rate base.

A. The Company included a cash working capital ("CWC") allowance of $3,184,324 based on the one-eighth O&M expense methodology.

Q. Is this methodology reasonable?

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[27] *Id.*

A. No. It is outdated and inaccurate. The methodology is simple, but does not reflect the leads and lags in the Company's operating cash flows. Only the lead/lag study approach measures these leads and lags and accurately determines the average investment by either the Company's customers or its investors.

Q. Has AEC performed and filed lead/lag studies in other jurisdictions?

A. Yes. Consequently, there is no need to guess the results of a lead/lag study if one had been performed by the Company for this case. AEC performed and filed lead/lag studies in rate cases before the Colorado Public Utilities Commission, Tennessee Regulatory Authority, Railroad Commission of Texas, and Virginia State Corporation Commission.[28]

In Colorado Docket No. 13AL-0496G (2012), Atmos filed a working capital analysis with $77.668 million in operating expenses and *negative* $2.773 million cash working capital. In Colorado Docket No. 14AL-0300G (2013), Atmos filed a working capital analysis with $103.090 million in operating expenses and *negative* $3.836 million in cash working capital. In Colorado Docket No. 15AL-0299G (2014), Atmos filed a working capital analysis with $105.723 million in operating expenses and *negative* $2.578 million in cash working capital.

[28] Atmos provided summaries of the results of these studies filed in various cases in various jurisdictions in response to AG 1-10. I have attached a copy of this response as my Exhibit___(LK-14).

In Tennessee Docket No. 12-00064 (2012), Atmos-Tennessee filed a working capital analysis with $127.490 million in operating expenses and $0.607 million in cash working capital, although that study erroneously included amounts for depreciation and return on equity. When these amounts are removed, the study reflects *negative* $1.523 million in cash working capital. In Tennessee Docket No. 12-00064 (2013), Atmos-Tennessee filed a working capital analysis with $132.984 million in operating expenses and $0.653 million in cash working capital, although that study erroneously included amounts for depreciation and return on equity. When these amounts are removed, the study reflects *negative* $1.583 million in cash working capital.

In Tennessee Docket No. 14-00146 (2014), Atmos-Tennessee filed a working capital analysis with $154.097 million in operating expenses and $1.211 million in cash working capital, although that study erroneously included amounts for depreciation and return on equity. When these amounts are removed, the study reflects *negative* $1.319 million in cash working capital. In Tennessee Docket No. 14-00146 (2016), Atmos-Tennessee filed a working capital analysis with $158.493 million in operating expenses and $0.956 million in cash working capital, although that study erroneously included amounts for depreciation and return on equity. When these amounts are removed, the study reflects *negative* $1.875 million in cash working capital.

In Texas Docket No. 10174 (2012), Atmos Mid-Tex filed a working capital analysis with $179.219 million in operating expenses and *negative* $1.957 million in cash working capital. In Statement of Intent in Texas (2013), Atmos Mid-Tex filed a working capital analysis with $173.655 million in operating expenses and *negative* $2.757 million in cash working capital.

In Virginia Docket No. PUE-2015-00119, Atmos Virginia filed a working capital analysis with *negative* $0.168 million in cash working capital, although that study erroneously included amounts for depreciation and deferred income taxes. When these amounts are removed, the study reflects *negative* $0.358 million in cash working capital.

The point of this recitation of working capital studies filed in other jurisdictions is to demonstrate the point that in *every* instance, when measured properly through the lead/lag study approach, Atmos had *negative* cash working capital.

Q. What is your recommendation?

A. I recommend that the Commission set the Company's cash working capital at $0 in the absence of a proper lead/lag study, even though there is no doubt that it should be negative. The one-eighth of O&M expense methodology is outdated and inaccurate. All the Company's lead/lag studies in other jurisdictions demonstrate unequivocally that a properly performed cash working capital study results in negative cash working capital, meaning that customers provide the Company with capital to fund other rate base investments.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the revenue requirement by $378,460. I multiplied the Company's proposed cash working capital times the Company's grossed-up rate of return.

The Proposed Regulatory Asset for Rate Case Expense Should Be Disallowed

Q. Please describe the Company's request for recovery of rate case expenses due to this proceeding.

A. The Company projects that it will incur $469,000 in rate case expenses in this proceeding. It included $351,682 in rate base (based on a 13 month average) and proposed a three year amortization, or $234,455 in amortization expense.

Q. Should the Commission authorize recovery of these expenses?

A. No. This case never should have been filed and rate case expenses of this magnitude, equivalent to 14.1% of its request, never should have been and should not be incurred in the future. The Commission should make this point by denying any recovery of these costs.

First, the requested rate increase of $3,213,606, as revised, is driven primarily by two issues. The proposed revenue requirement reflects an increase in the return on equity to 10.5% from 9.8% granted in Case No. 2013-00148 and an increase in the common equity ratio to 55.32% from 49.16% granted in Case No. 2013-00148, neither of which are justified.

The increase in the return on equity to 10.5% comprises $1,979,198 of the requested increase and the increase in the common equity ratio to 55.32% comprises another $1,967,688 of the requested increase, for a total of $3,946,886, using the AG's recommended rate base in this proceeding. These amounts would be greater if I had used the Company's proposed rate base instead of the AG's recommended rate base.

In other words, absent the unjustified proposed increases in these two components, and less than two years after the Commission decided these two issues in Case No. 2013-00148, the revenue requirement would reflect a rate *reduction*, not an increase.

Second, the AG has been forced to incur the costs of multiple experts to respond to the Company's spurious request. Similarly, the Commission and Staff have been forced to expend their limited resources to address the Company's spurious request.

III. OPERATING INCOME ISSUES

<u>The Amortization Expense for Rate Case Expenses Should Be Disallowed</u>

Q. Did you address this issue in the Rate Base Issues section of your testimony?

A. Yes. I reflect the reduction in amortization expense and the revenue requirement on the table in the Summary section of my testimony.

<u>The Proposed Amortization Period for the PLR Request Regulatory Asset Should be Extended from One Year to Three Years</u>

Q. Please describe the Company's request for recovery of the cost to obtain a PLR related to the DTA – NOL issue.

A. The Company incurred and deferred $33,000 to obtain a PLR related to the DTA – NOL issue. The Company proposes a one year amortization of this expense and included the 13 month average of this amount as a regulatory asset in rate base, offset by the related DTL.

Q. Is a one year amortization of this cost reasonable?

A. No. Although this is a relatively small expense, the Company likely will over-recover if the Commission adopts the one year amortization period proposed by the Company.

If the Commission adopts the one year amortization period and the Company's base rates are not reset for three years after the effective date of rates resulting from this proceeding, then the Company would recover $99,000, or three times its actual cost for the PLR, instead of $33,000.

That is not reasonable. Instead, the Commission should attempt to match the amortization period to the timing of the effective date of rates resulting from the Company's next base rate case to avoid multiple recoveries of the deferred cost.

Q. What do you recommend?

A. I recommend a three year amortization period, although the timing of the Company's next base rate case is unknown. This is a reasonable assumption, although it may be longer due to the Company's ability to recover PRP costs through the PRP surcharge rider.

Q. Have you quantified the effect of your recommendation?

A. Yes. The longer amortization period will reduce the Company's O&M expense and the revenue requirement by $22,022. I separately quantified the effect of this recommendation on rate base in the Rate Base Issues section of my testimony.

<u>The Depreciation Expense Should Be Reduced to Reflect Lower Capital Expenditures and Plant Additions</u>

Q. Have you quantified the effect of your recommendation to reduce the Company's projected capital expenditures and plant additions addressed in the Rate Base Issues section of your testimony?

A. Yes. The effect is a reduction of $19,412 in depreciation expense and the revenue requirement.[29] I reflect this amount on the table in the Summary section of my testimony.

<u>The Commitment and Banking Fees Should Be Included in Operating Expenses</u>

Q. Have you included the commitment and banking fees in operating expenses instead of in the cost of short-term debt?

A. Yes. In accordance with Mr. Baudino's recommendation, I have included $119,560 for these expenses in operating expenses. I made an offsetting adjustment to the revenue requirement for the reduction in short-term debt interest expense, which I address in the Rate of Return Issues section of my testimony.

IV. RATE OF RETURN ISSUES

<u>Quantification of AG's Recommended Capital Structure</u>

Q. Have you quantified the effect of the AG's recommendation for the capital structure?

A. Yes. The AG recommendation reduces the Company's revenue requirement by

[29] The calculations are detailed on my Exhibit___(LK-3).

$1,153,299 using the Company's proposed costs for short-term debt, long-term debt, and the return on equity. Mr. Baudino recommends that the Commission reject the Company's proposed capital structure, which reflects a substantial increase in the common equity ratio, and instead adopt a more balanced capital structure consistent with the Company's historic capital structure and its debt ratings. As Mr. Baudino notes, if the Commission does not adopt the AG's recommendation for the capital structure, then it should adopt a lower return on equity to reflect the interelationship between the cost of equity and the common equity ratio.[30]

<u>Quantification of AG's Recommendations to Reduce the Cost of Short Term Debt</u>

Q. Have you quantified the effect of the AG's recommendation to modify the cost of short term debt from the cost proposed by the Company in its filing?

A. Yes. This recommendation reduces the cost of short-term debt to 0.39% and reduces the revenue requirement by $147,101, using the rate base adjusted for the AG recommendations that I addressed in the Rate Base Issues section of my testimony and the capital structure recommended by Mr. Baudino.[31] Mr. Baudino recommends that the

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[30] The calculations are detailed in Section II of my Exhibit___(LK-15). Section I of that exhibit replicates the Company's request, including the gross-up for income taxes on the equity return component. In Section II, I calculate the reduction in the grossed-up rate of return compared to the Company's request and multiply the difference times the rate base, adjusted for my recommendations.

[31] The calculations are detailed in Section III of my Exhibit___(LK-15). In Section III, I reduce the grossed-up rate of return to reflect the elimination of the commitment and banking fees from the cost of short-term

commitment and banking fees be removed from the cost of short term debt and instead be included in operating expenses. I have reflected the effect of this recommendation on operating expenses in a separate adjustment and addressed the effect in the Operating Income Issues section of my testimony.

Quantification of AG's Recommendations for Return on Equity

Q. Have you quantified the effect of the AG's recommendation for the return on common equity?

A. Yes. A return on equity of 9.0% reduces the Company's revenue requirement by $3,830,361 using the AG recommendation for the capital structure. Mr. Baudino recommends a return on equity of 9.0% if the Commission adopts the AG recommendation for the capital structure. Each 10 basis points in the return on equity in either direction affects the revenue requirement by $255,357. These amounts are incremental to the reductions in the revenue requirement for the AG recommendations on the cost of short term debt.[32]

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debt. I calculate the reduction in the grossed-up rate of return compared to Section II and multiply the difference times the rate base, adjusted for my recommendations.

[32]The computations are detailed in Section IV of my Exhibit__(LK-15).

Q. Have you quantified the effect of the AG's alternative recommendation for the return on common equity if the Commission adopts the Company's proposed capital structure instead of the AG's recommendation?

A. Yes. Under this alternative, a return on equity of 8.75% reduces the Company's revenue requirement by $4,703,101 using the Company's capital structure and reflecting the AG recommendation for the cost of debt. Under this alternative, the Commission would adopt the Company's proposed projected capital structure and not adopt the AG recommendation to reflect the historic capital structure. Each 10 basis points in the return on equity in either direction affects the revenue requirement by $268,749.[33]

V. DIVISION 002 AND DIVISION 091 COMPOSITE FACTORS

Q. Please describe the composite factors used to allocate AEC shared services costs incurred at the corporate level by Division 002 and at Kentucky Mid-States level by Division 091.

A. The costs that are incurred at the corporate level by Division 002 are allocated to the Kentucky Mid-States Division in the filing using a composite factor. The costs allocated to the Kentucky Mid-States Division are allocated to Kentucky using a composite factor.

The composite factors for each division are comprised of three components with

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[33] The computations are detailed in Section V of my Exhibit__(LK-15).

equal weighting: gross direct property plant and equipment, average number of customers, and total O&M expense.[34] AEC uses various versions of the composite factor, e.g., all companies, utility, and regulated only, among others.

In the filing, Atmos calculated a composite factor of 10.71% and allocated costs from Division 002 to Division 091 using this factor. Atmos calculated a composite factor of 49.09% and allocated the Division 002 costs allocated to Division 091, along with the costs incurred directly by Division 091, to the Kentucky jurisdiction using this factor.

Q. Are the composite factors used for Division 002 and Division 091 reasonable?

A. No. Only one of the three components of the composite factor is reasonable, the gross direct property plant and equipment. The number of customers is not reasonable because there is a separate customer allocation factor that is used for customer costs, particularly the costs from Division 012 *Call Center* customer support. It should not be used to allocate costs that are not caused by number of customers. The total O&M is not reasonable because it is not a comprehensive measure of all expenses that are managed by Division 002.

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[34] Refer to Schedule Allocation in the revised revenue requirement model provided in response to Staff 2-21 and WP ATT17 Composite Factors for Rates. I have attached a copy of these schedules as my Exhibit___(LK-

Q. Is there a better and more comprehensive measure of all expenses that are managed by Division 002 than total O&M expenses?

A. Yes. Total operating expenses is a better and more comprehensive measure of all costs. In addition to O&M expenses, it includes taxes other than income taxes and depreciation and amortization expenses.

Q. Do the two factors, gross direct property plant and equipment and the total operating expenses provide a comprehensive proxy for all of the costs that are incurred and managed by Division 002?

A. Yes. The gross direct property plant and equipment is a reasonable proxy for rate base and the total operating expenses are a reasonable proxy for the operating expenses included in the filing.

Q. What is your recommendation?

A. I recommend that the Commission modify the composite factor so that it is based on equal weighting of gross direct property plant and equipment and total operating expenses.

Q. Have you quantified the effect of your recommendation?

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16) for ease of reference.

A. Yes. The effect is to reduce the revenue requirement by $922,647.[35]

Q. Does this complete your testimony?

A. Yes.

[35] I calculated the revised allocation factors for Division 002 and Division 091 using these two measures. The calculations are shown on my Exhibit___(LK-17). I then used the revised allocation factors in the Company's revenue requirement model provided in response to Staff 2-21.

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 2016

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

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5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

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8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

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3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.

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10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.

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11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.

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06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

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10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.

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10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

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04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.

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12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

Expert Testimony Appearances
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Lane Kollen
as of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

**Expert Testimony Appearances
of
Lane Kollen
as of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.

Expert Testimony Appearances
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as of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal Supplemental Rebuttal, Supplemental Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.

Expert Testimony Appearances
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Lane Kollen
as of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/16	EL01-88 Remand	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
04/16	39971	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.

EXHIBIT ____ (LK-2)

Atmos Energy Corporation - Kentucky/Mid States Division
Remove Capital Adds Escalation in Projected Year for KY-Div Non-PRP Plant
Revenue Requirement Effect on Rate Base
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017
$

See AG WP File - ATT26 - KY Plant Data - Fall 2015 Case Adjusted for Changed Escalation Rate
See further calculations summarized on tab "Capital Spending."

Effects of Change in Capital Adds Escalation Rate for KY Non-PRP from 1.10 to 1.00
All Numbers Below are KY Div Only

Gross Plant 13 month Avg at 1.10 as Filed	530,417,572
Gross Plant 13 month Avg at 1.00 as Adjusted	529,885,389
Change	(532,183)
A/D 13 month Avg at 1.10 as Filed	167,963,071
A/D 13 month Avg at 1.00 as Adjusted	168,068,838
Change	105,767
Net Change in Rate Base to Remove 10% Escalation on Non-PRP Capital Adds	(426,416)
As Filed Grossed Up Rate of Return	11.89%
Reduction in Revenue Requirement by Removing 10% Escalation on Non-PRP Capital Adds	(50,680)

EXHIBIT ____ (LK-3)

Atmos Energy Corporation - Kentucky/Mid States Division
Remove Capital Adds Escalation in Projected Year for KY-Div Non-PRP Plant
Revenue Requirement Effect on Depreciation Expense
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017

See AG WP File - ATT26 - KY Plant Data - Fall 2015 Case Adjusted for Changed Escalation Rate
See further calculations summarized on tab "Capital Spending."

Effects of Change in Capital Adds Escalation Rate for KY Non-PRP from 1.10 to 1.00
All Numbers Below are KY Div Only

Depr Exp at 1.10 as Filed	18,207,839
Amount Not in Calculation Based on O&M Factor	(148,049)
Depr Exp. In Filing for KY Division Only - See Below and Sch B-3.1	18,059,790
Depr Exp at 1.00 as Adjusted	18,188,239
Amount Not in Calculation Based on O&M Factor	(147,861)
Depr Exp. As Adjusted for KY Division Only - See Below and Sch B-3.1	18,040,378
Revenue Requirement Change in Depr Expense	(19,412)

See Schedule B-3.1 for allocated Depr Only that rolls into filing - As Filed

39200	Trucks	$ 54,944	43.47%		23,883.84
39202	Trailers	$ 3,303	43.47%		1,435.62
39400	Power Operate	$ 166,870	43.59%		72,746.07
39603	Backhoes	$ 9,210	2.00%		184.21
39604	Welders	$ 12,217	2.00%		244.35
		$ 246,543		$	98,494

See Schedule B-3.1 for allocated Depr Only that rolls into filing - As Adjusted

39200	Trucks	$ 54,944	43.47%		23,883.84
39202	Trailers	$ 3,303	43.47%		1,435.62
39400	Power Operate	$ 166,537	43.59%		72,600.89
39603	Backhoes	$ 9,210	2.00%		184.21
39604	Welders	$ 12,217	2.00%		244.35
		$ 246,210		$	98,349

EXHIBIT ____ (LK-4)

REQUEST:

Please refer to the electronic version of the detailed AD IT Workpapers provided by the Company in response to Staff 1-59 and the updated version provided in response to Staff 2-21. Refer further to the worksheet tab for Division 002- Shared Services.

For each of the following account 190 ADIT descriptions and amounts as of May 31, 2017: (1) describe in detail the temporary difference that caused the AD IT, (2) describe how and where the Company included or excluded the cost giving rise to the temporary differences in the rate base and revenue requirement, and (3) provide the Company's justification for including the AD IT in the rate base and revenue requirement, particularly if the underlying temporary difference is not included in the rate base and revenue requirement.

a. MIP/VPP Accrual - $1,253,998

b. Self Insurance- Adjustment - $4,576,432

c. SEBP Adjustment - $24,316,653

d. Restricted Stock Grant Plan - $7,385,565

e. Rabbi Trust - $1,534,495

f. Restricted Stock- MIP - $9,513,920

g. Director's Stock Awards - $4,119,248

h. Charitable Contribution Carryover - $10,525,877

i. VA Charitable Contributions - $(6,968,861)

RESPONSE:

a) **MIP/VPP Accrual**

Bonuses under the Management Incentive Plan and Variable Pay Plan are accrued throughout the year and paid subsequent to year end. For financial reporting purposes, these accruals are made throughout the year with a corresponding entry to expense. For tax, these amounts are only deductible when paid during or within 2 ½ months after the tax year end, per IRC §404. As a result, a deferred tax asset is booked for the amount expensed for books but not yet deductible for tax.

The Company removed expenses for incentive compensation, including MIP/VPP, as part of its initial petition as shown on Schedule F-10. While the Company has traditionally included these costs and related deferred taxes in revenue requirement, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment, provided it is appropriately removed from all divisions allocable to Kentucky.

b) **Self -Insurance Adjustment**

The Company self-insures itself for certain losses and contingencies. The Company accrues an expense to establish the self-insurance reserves on the general ledger. Once a loss, which is covered by a self-insurance reserve, is realized by the Company, the payment of that loss is made out the accrual which has been established on the general ledger. For tax purposes, pursuant to §461(h), liabilities may only be deducted when all events which establish the fact of the liability have occurred, the amounts can be determined with reasonable accuracy, and economic performance has occurred. A deferred tax asset is booked for those expenses recognized for books but not yet deductible for tax.

The expense accrual described in the preceding paragraph is not allocated to operating divisions and therefore not in revenue requirement. While the inclusion of the related deferred taxes has traditionally remained in ADIT, including in Case No. 2013-00148, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

c) **SEBP Adjustment**

The Company accrues a liability to meet the future obligations associated with supplemental executive benefits. For book purposes, the accruals are recorded to expense and a liability is established. For tax purposes, supplemental executive benefits are not deductible until paid, pursuant to §409A. A deferred tax asset is booked for those expenses currently recognized for financial reporting purposes but not yet deductible for tax.

The accrual for this underlying expense is booked and budgeted in O&M and therefore in revenue requirement as it has traditionally been, including in Case No. 2013-00148. It is therefore appropriate to include the related deferred tax item in ADIT, as it has traditionally been, including in Case No. 2013-00148.

d) **Restricted Stock Grant Plan**

Restricted stock units are granted to employees. There is a difference between when the expense associated with the unit grants is recognized for financial reporting purposes versus when the expense is recognized for tax purposes. For financial reporting purposes, the value of the units at the date of grant is amortized over three years starting on the date of grant. For tax purposes, pursuant to IRC §83(h), the expense cannot be recognized until the units vest and stock is awarded. This results in a timing difference and a deferred tax asset for the amortization recognized for financial reporting purposes but not yet deductible for tax.

The Company removed expenses for incentive compensation, including restricted stock, as part of its initial petition as shown on Schedule F-10. While the Company has traditionally included these costs and related deferred taxes in revenue requirement, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

e) **<u>Rabbi Trust</u>**

Accumulated appreciation, contributions and distributions on Rabbi Trust assets are tracked for financial statement purposes. Estimated trust income is booked to the general ledger prior to receipt of the trust statements. A true-up entry is booked once the statement arrives. For tax purposes, an estimate of trust income is not accrued. Only actual trust income is recognized for tax purposes. Book and tax basis are the same for cash contributions and distributions. The Rabbi Trust deferred tax balance equals the one month lag between estimated trust income per books and actual trust income per the trust statements.

The accounting entries described in the preceding paragraph are in revenue requirement as they have traditionally been, including in Case No. 2013-00148. It is therefore appropriate to include the related deferred tax item in ADIT, as it has traditionally been, including in Case No. 2013-00148.

f) **<u>Restricted Stock MIP</u>**

Employees can choose to convert their Management Incentive Plan bonus to time-lapse restricted stock. When this occurs, the restricted stock granted is amortized over a three year period for financial reporting purposes. For tax, the compensation expense deduction is not allowed until the restricted stock has vested, pursuant to IRC §83(h). This timing difference results in a deferred tax asset equal to the book amortization on the restricted stock not yet deductible for tax.

The Company removed expenses for incentive compensation, including MIP/VPP and restricted stock, as part of its initial petition as shown on Schedule F-10. While the Company has traditionally included these costs and related deferred taxes in revenue requirement, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

g) **Director's Stock Awards**

For financial reporting purposes, the expense for Director's Stock is recorded in the year the stock is granted. Pursuant to IRC §83(h), for tax purposes the expense cannot be recognized until the stock is fully vested. A deferred tax asset is created for the book expense recognized but not yet deductible for tax.

The accrual for this underlying expense is booked and budgeted in O&M and therefore in revenue requirement as it has traditionally been, including in Case No. 2013-00148. It is therefore appropriate to include the related deferred tax item in ADIT, as it has traditionally been, including in Case No. 2013-00148.

h) **Charitable Contribution Carryover**

For financial statement purposes, charitable contributions are deducted when paid. For tax purposes, pursuant to §170(b)(2) the total deductions for any taxable year shall not exceed 10 percent of the taxpayer's taxable income. Per §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years in order of time. The ADIT item represents the contributions deducted for book purposes and not yet deductible for tax.

The contributions described in the preceding paragraph are typically booked to account 426 and therefore not in revenue requirement. While the inclusion of the related deferred taxes has traditionally remained in ADIT, including in Case No. 2013-00148, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

i) **VA Charitable Contributions**

Pursuant to §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years in order of time. This valuation allowance was established to reduce the deferred tax asset related to charitable contributions due to circumstances leading the Company to believe it is more likely than not that the benefit from certain charitable contributions will not be realized.

The contributions described in the preceding paragraph are typically booked to account 426 and therefore not in revenue requirement. While the inclusion of the related deferred taxes has traditionally remained in ADIT, including in Case No. 2013-00148, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

Respondents: Pace McDonald and Greg Waller

EXHIBIT ____ (LK-5)

REQUEST:

Please refer to the electronic version of the detailed AD IT Workpapers provided by the Company in response to Staff 1-59 and the updated version provided in response to Staff 2-21. Refer further to the worksheet tab for Division 091- KY/Mid States.

For each of the following account 190 AD IT descriptions and amounts as of May 31, 2017: (1) describe in detail the temporary difference that caused the AD IT, (2) describe how and where the Company included or excluded the cost giving rise to the temporary differences in the rate base and revenue requirement, and (3) provide the Company's justification for including the AD IT in the rate base and revenue requirement, particularly if the underlying temporary difference is not included in the rate base and revenue requirement.

a. MIP/VPP Accrual $141,947

b. SEBP Adjustment $1,364,197

c. Charitable Contribution Carryover - $163,960

d. Reg Asset Benefit Accrual - $380,148

RESPONSE:

a) **MIP/VPP Accrual**
Bonuses under the Management Incentive Plan and Variable Pay Plan are accrued throughout the year and paid subsequent to year end. For financial reporting purposes, these accruals are made throughout the year with a corresponding entry to expense. For tax, these amounts are only deductible when paid during or within 2 ½ months after the tax year end, per IRC §404. As a result, a deferred tax asset is booked for the amount expensed for books but not yet deductible for tax.

The Company removed expenses for incentive compensation, including MIP/VPP, as part of its initial petition as shown on Schedule F-10. While the Company has traditionally included these costs and related deferred taxes in revenue requirement, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment, provided it is appropriately removed from all divisions allocable to Kentucky.

b) **SEBP Adjustment**
The Company accrues a liability to meet the future obligations associated with supplemental executive benefits. For book purposes, the accruals are recorded to

expense and a liability is established. For tax purposes, supplemental executive benefits are not deductible until paid, pursuant to §409A. A deferred tax asset is booked for those expenses currently recognized for financial reporting purposes but not yet deductible for tax.

The accrual for this underlying expense is booked and budgeted in O&M and therefore in revenue requirement as it has traditionally been, including in Case No. 2013-00148. It is therefore appropriate to include the related deferred tax item in ADIT, as it has traditionally been, including in Case No. 2013-00148.

c) **Charitable Contributions Carryover**

For financial statement purposes, charitable contributions are deducted when paid. For tax purposes, pursuant to §170(b)(2) the total deductions for any taxable year shall not exceed 10 percent of the taxpayer's taxable income. Per §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years in order of time. The ADIT item represents the contributions deducted for book purposes and not yet deductible for tax.

The contributions described in the preceding paragraph are typically booked to account 426 and therefore not in revenue requirement. While the inclusion of the related deferred taxes has traditionally remained in ADIT, including in Case No. 2013-00148, upon further review, the Company would not oppose removal of the ADIT item consistent with the underlying expense treatment.

d) **Reg Asset Benefit Accrual**

For financial statement and regulatory reporting purposes the expense for certain benefit accruals is capitalized when incurred. For tax purposes such expenses are deductible when paid as ordinary and necessary business expenses under IRC Sec. 162.

This item relates to the Company's Tennessee jurisdiction. Upon further review, it is appropriate to exclude it from ADIT in this case.

Respondents: Pace McDonald and Greg Waller

EXHIBIT ____ (LK-6)

Atmos Energy Corporation - Kentucky Division
AG Recommendation to Exclude Certain DTAs from Rate Base
KPSC Case No. 2015-00343
Test Year Ended May 31, 2017
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See Responses to AG 2-13 and 2-14

Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
MIP/VPP Accrual	1,253,998	5.26%	65,930	11.89%	7,836
Self Insurance Adjustment	4,576,432	5.26%	240,610	11.89%	28,597
Restricted Stock Grant Plan	7,385,565	5.26%	388,303	11.89%	46,150
Restricted Stock MIP	9,513,920	5.26%	500,203	11.89%	59,450
Charitable Contribution Carryover	10,525,877	5.26%	553,407	11.89%	65,773
VA Charitable Contribution Carryover	(6,968,891)	5.26%	(366,396)	11.89%	(43,546)
Total Division 002	26,286,901		1,382,057		164,259

Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
MIP/VPP Accrual	141,947	49.09%	69,682	11.89%	8,282
Charitable Contribution Carryover	163,960	49.09%	80,489	11.89%	9,566
Reg Asset Benefit Accrual	380,148	49.09%	186,616	11.89%	22,180
Total Division 091	686,055		336,788		40,027

Total First Category Reduction to Revenue Requirement Related to Account 190 ADIT $ 204,286

EXHIBIT ____ (LK-7)

Atmos Energy Corporation - Kentucky Division
AG Recommendation to Subtract Temporary Difference Associated with Certain DTAs
KPSC Case No. 2015-00343
Test Year Ended May 31, 2017
$

See Responses to AG 2-13 and 2-14

Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	Temp Diff Revenue Req KY Division
SEBP Adjustment	24,316,653	62,510,676	5.26%	3,286,554	11.89%	390,610
Rabbi Trust	1,534,495	3,944,717	5.26%	207,397	11.89%	24,649
Director's Stock Awards	4,119,248	10,589,326	5.26%	556,743	11.89%	66,169
Total Division 002	29,970,396	77,044,720		4,050,694		481,428

Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	As-Filed Grossed-Up Rate of Return	DTA Revenue Req KY Division
SEBP Adjustment	1,364,197	3,506,933	49.09%	1,721,570	11.89%	204,610

Total Second Category Reduction to Revenue Requirement Related to Account 190 ADIT $ 686,038

EXHIBIT ____ (LK-8)

Atmos Energy Corporation - Kentucky/Mid States Division
Attorney General Recommendation to Remove Fed NOL ADIT in Account 190
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017
$

See WP File - ATT2 - ADIT for KY - Fall 2015 in Revised ADIT Filing in Response to Staff 2-21

		13 Month Average
Division 2 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)		
FD-NOL Credit Carryforward - Non Reg - Removed in Filing So Not Considered		(227,845,749)
Included in Filing:		
FD-NOL Credit Carryforward - Utility		407,851,903
FD-NOL Credit Carryforward - Other		(2,330,152)
Total Division 2 Net NOL Credit Carryforward in Account 190 ADIT Before Filing Adjustment		405,521,751
KY Mid States Division Allocation	10.71%	
KY Jurisdiction Allocation Factor	49.09%	
KY Jurisdictional Percentage		5.26%
KY Jurisdictional Percentage of FD-NOL Credit Carryforward ADIT that Should be Removed from Rate Base Based on Booked Amounts		$21,320,663
Add: Forecasted Change in NOL Credit Carryforward ADIT Reflected in Filing (Sch B-5 F) - KY Juris.		8,076,557
KY Jurisdiction NOL Credit Carryforward ADIT in Account 190 to Remove from Rate Base		29,397,220
As Filed Grossed Up Rate of Return		11.89%
Reduction in Revenue Requirement by Removing Fed NOL ADIT from Rate Base		(3,493,884)

EXHIBIT ____ (LK-9)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Computation of State & Federal Income Tax
Base Period: Twelve Months Ended February 29, 2016
Forecasted Test Period: Twelve Months Ended May 31, 2017

Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(e)
Schedule E
Witness: Waller

Line No.	Description	Base Period Unadjusted	Adjustments	Test Period Fully Adjusted	Sched. Ref.
		(1)	(2)	(3)	
1	Operating Income before Income Tax & Interest	$ 31,501,159	$ 4,906,044	$ 36,407,204	C-2
2	Interest Deduction	7,209,861	529,612	7,739,473	*
3	Taxable Income	$ 24,291,298	$ 4,376,433	$ 28,667,731	
4	Composite Tax Rate (state & federal)	38.900%		38.900%	* *
5	State & Federal Income Tax	$ 9,449,315	$ 1,702,432	$ 11,151,747	
	* Interest Expense Calculation:				
6	13 Month Average Rate Base	$295,969,028		$335,042,110	B-1
7	Weighted cost of Debt	2.44%		2.31%	J-1
8	Interest Expense	$ 7,209,861		$ 7,739,473	

9	2015 * * Composite Tax Rate Calculation: 6.00% + 35%(100% - 6.00%) = 38.900%	
10	State Tax Rate	6.00%
11	Federal Tax Rate	35.00%

EXHIBIT ____ (LK-10)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Deferred Credits and Accumulated Deferred Income Taxes
as of May 31, 2017

Data:_____Base Period__X__Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

FR 16(8)(b)5
Sch. B-5 F
Witness: Waller

Line No.	Account	Period End	Kentucky- Mid States Divisior Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	13-Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
	DIVISION 09								
1	Account 190 - Accumulated Deferred Income Taxes	$ 1,904,270	100%	100%	$ 1,904,270	$ 1,904,270	100%	100%	$ 1,904,270
2									
3	Account 282 - Accumulated Deferred Income Taxes	(99,006,302)	100%	100%	(99,006,302)	(95,955,182)	100%	100%	(95,955,182)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(96,035)	100%	100%	(96,035)	(96,035)	100%	100%	(96,035)
6									
7	Div 09 Accumulated Deferred Income Taxes	$ (97,198,067)			$(97,198,067)	$ (94,146,946)			$ (94,146,946)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$484,045,051	10.71%	49.09%	$ 25,449,094	$484,045,051	10.71%	49.09%	$ 25,449,094
11									
12	Account 282 - Accumulated Deferred Income Taxes	(26,699,472)	10.71%	49.09%	(1,403,748)	(26,536,835)	10.71%	49.09%	(1,395,197)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	22,822,185	10.71%	49.09%	1,199,896	22,822,185	10.71%	49.09%	1,199,896
15									
16	Div 02 Accumulated Deferred Income Taxes	$480,167,764			$ 25,245,243	$480,330,401			$ 25,253,793
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ (410,946)	10.86%	52.60%	$ (23,474)	$ (410,946)	10.86%	52.60%	$ (23,474)
19									
20	Account 282 - Accumulated Deferred Income Taxes	(30,098,212)	10.86%	52.60%	(1,719,286)	(30,344,721)	10.86%	52.60%	(1,733,367)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.86%	52.60%	0	0	10.86%	52.60%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (30,509,158)			$ (1,742,760)	$ (30,755,667)			$ (1,756,842)
25	**DIVISION 91**								
26	Account 190 - Accumulated Deferred Income Taxes	$ 6,664,194	100%	49.09%	$ 3,271,484	$ 6,664,194	100%	49.09%	$ 3,271,484
27									
28	Account 255 - Accumulated Deferred Investment Tax Credits	(11,421)	100%	49.09%	(5,607)	(11,421)	100%	49.09%	(5,607)
29									
30	Account 282 - Accumulated Deferred Income Taxes	(5,460,914)	100%	49.09%	(2,680,787)	(5,450,864)	100%	49.09%	(2,675,854)
31									
32	Account 283 - Accumulated Deferred Income Taxes - Other	(1,472,160)	100%	49.09%	(722,690)	(1,472,160)	100%	49.09%	(722,690)
33									
34	Div 91 Accumulated Deferred Income Taxes	$ (280,300)			$ (137,601)	$ (270,251)			$ (132,667)
35									
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$352,180,239			$(73,833,185)	$355,157,537			$ (70,782,662)
38	*(excluding forecasted change in NOLC)*								
39	**Forecasted Change in NOLC**								8,076,557
40									
41	**Forecasted 13-month Average ADIT in Rate Base**								**(62,706,105)**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Deferred Credits and Accumulated Deferred Income Taxes
as of May 31, 2017

Data:_____Base Period___X__Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

FR 16(8)(b)5
Sch. B-5 F
Witness: Waller

Line No.	Account	Period End	Kentucky- Mid States Divisior Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	13-Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
42									
43	**Calculation of Change in NOLC**								
44	**(from 13-month average Base Period to 13-month average Forecasted Period**								
45									
46	Forecasted Test Period			Schedule Reference					
47									
48	13-month average Rate Base			B.1 F		335,042,110			
49									
50	Required Operating Income			A.1		27,205,419			
51									
52	Interest Deduction			E.1		7,739,473			
53									
54	Return on Equity Portion of Rate Base			line 50 - line 52		19,465,946			
55									
56	Return, grossed up for Income Tax	38.90%		Line 54 / (1-tax rate)		31,859,159			
57									
58	Tax Expense on Return	38.90%		Line 56 x tax rate		12,393,213			
59									
60	Change In ADIT, excluding forecasted change in NOLC			Line 37; B.5 B		(20,469,770)			
61	Required Change in NOLC					8,076,557			
62									
63	**Total Required Change in Accumulated Deferred Income Taxes**[1]			**B.1 F; B.1 B**		**(12,393,213)**			
64									
65									
66	**ADIT Reconciliation**								
67	**13-Month Average ADIT, Base Period**			**B.5 B**		**(50,312,892)**			
68									
69	13-Month Average ADIT, Forecasted Period, excl, Change in NOLC			Line 37		(70,782,662)			
70	Change in NOLC			Line 39		8,076,557			
71	**Forecasted 13-month Average ADIT in Rate Base**					**(62,706,105)**			
72									
73	**Total Required Change in Accumulated Deferred Income Taxes**			Line 71 - Line 67		**(12,393,213)**			
74									
75									
76	[1] *Because the Company is in a NOLC position, the total change in ADIT must equal the tax expenses included in revenue requirement*								

EXHIBIT ____ (LK-11)

REQUEST:

Refer to the following

- Company's response to AG 1-22(d) wherein Mr. McDonald states:

"Unlike PLR 201418024, the provision for deferred taxes in KPSC 2013-00148 was impacted by both the entire difference between accelerated tax and regulatory depreciation AND the recording of an NOLC DTA. If the Company's NOLs had been excluded from the deferred tax provision, the Company's provision for income taxes would have been higher than a tax provision included in the filing."

- Company's response to AG 1-23(e) wherein Mr. McDonald states:

"In Case No. 2013-00148, Mr. McDonald believes the Commission correctly included the credit related to the NOLin the deferred income tax provision and included the DTA for NOLC in the balance of deferred taxes applied to rate base."

- Company's response to AG 1-24(b) wherein Mr. McDonald states:

"The filing in this proceeding does not impose on customers a deferred tax charge on the entire difference between book and tax depreciation whether or not the deduction created an NOLC. The deferred charge imposed in this proceeding includes a credit related to the NOL."

a. Please confirm that the terms "deferred tax provision," "deferred income tax provision," and "deferred tax charge" are interchangeable and refer to income tax *expense* included in the revenue requirement. If this is not the case, then please differentiate the terms as used in the referenced responses.

b. Refer to Schedule E in Case No. 2013-00148 wherein the income tax *expense* for the base year and test period were calculated. In that calculation, the Company started with operating income *before* income tax and interest and then subtracted synchronized interest to calculate taxable income. The income tax *expense* was then calculated by multiplying the statutory combined federal and state income tax rate times taxable income. Please confirm that this correctly describes the calculation of income tax *expense* in that proceeding. If this does not correctly describe the calculation of income tax *expense* in that proceeding, please provide in detail the process that was taken to calculate income tax *expense* for that base year.

c. Refer to Schedule E in Case No. 2013-00148. Please confirm that the Company did NOT credit (reduce) income tax *expense* in either the base year or the test period to reflect an NOLin either period. If this is not correct, then provide the credit to income tax *expense* in the base year and in the test period for the NOLand provide a narrative description for each period of how the credit was applied, along with a copy of all workpapers and supporting documentation, including electronic workpapers with formulas intact.

d. In Case No. 2013-00148, if the Company reflected a reduction in income tax *expense* on any schedule other than Schedule E to reflect an NOLin either the base year or the test period, then please identify the schedule and/or any supporting workpapers and provide the specific reduction in income tax *expense* due to the NOLin each period.

e. Refer to Schedule E in this proceeding wherein the income tax *expense* for the base year and test period were calculated. In that calculation, the Company started with operating income before income tax and interest and then subtracted synchronized interest to calculate taxable income. The income tax *expense* was then calculated by multiplying the statutory combined federal and state income tax rate times taxable income. Please confirm that this correctly describes the calculation of income tax *expense* in this proceeding. If this does not correctly describe the calculation of income tax *expense* in that proceeding, please provide in detail the process that was taken to calculate income tax *expense* for that.

f. Refer to Schedule E in this proceeding. Please confirm that the Company did NOT credit (reduce) income tax *expense* in either the base year or the test period to reflect an NOL in either period. If this is not correct, then provide the credit to income tax *expense* in the base year and in the test period for the NOLin each period and a narrative description of how the credit was applied, along with a copy of all workpapers and supporting documentation, including electronic workpapers with formulas intact.

g. In this proceeding, if the Company reflected a reduction in income tax *expense* on any schedule other than Schedule E to reflect an NOLin either the base year or the test period, then please identify the schedule and/or any supporting workpapers and provide the specific reduction in income tax *expense* due to the NOLin each period.

RESPONSE:

a) Confirmed.

b) This description describes the mechanical calculation of total income tax expense using a statutory tax rate. Total income tax expense is the combination of the current tax provision and the deferred tax provision.

c) The Company cannot confirm this. Calculating income tax expense by applying a statutory tax rate to base year or test period income results in the accrual of all income taxes owed on that income whether the tax is owed currently (current tax provision) or deferred to a future period (deferred tax provision). Calculating tax expense in this manner results in the total tax that will be owed on the income being accrued to the period (and included in cost of service) in which it was earned. Any differences between total tax accrued and cash taxes paid are reflected properly on the balance sheet (and as a reduction to Rate Base) in the form of Accumulated Deferred Income Taxes (ADIT).

The total tax expense on the income cannot be higher or lower than this calculation unless an item of income, expense or a tax attribute is permanently excluded from either the current tax provision or the deferred tax provision. If any item, such as the effect of establishing an NOL, were excluded from the calculation, the total tax expense would be higher or lower than the taxes calculated using a statutory rate.

Consistent with prior proceedings, the tax expense in Case No. 2013-00148 is equal to the income times the statutory tax rate. No items, including the credit related to the NOL, were excluded. If the NOL had been excluded, the underlying deferred tax provision would have been higher thereby resulting in a total tax expense greater than the statutory rate.

d) Total tax expense was calculated using the methodology described in items b and c. The impact of the Company's NOL has not been excluded on any schedules in Case No. 2013-00148.

e) This description describes the mechanical calculation of total income tax expense using a statutory tax rate. Total income tax expense is the combination of the current tax provision and the deferred tax provision.

f) The Company cannot confirm this. Calculating income tax expense by applying a statutory tax rate to base year or test period income results in the accrual of all income taxes owed on that income whether the tax is owed currently (current tax provision) or deferred to a future period (deferred tax provision). Calculating tax expense in this manner results in the total tax that will be owed on the income being accrued to the period (and included in cost of service) in which it was earned. Any differences between total tax accrued and cash taxes paid are reflected properly on the balance sheet (and as a reduction to Rate Base) in the form of Accumulated Deferred Income Taxes (ADIT).

The total tax expense on the income cannot be higher or lower than this calculation unless an item of income, expense or a tax attribute is permanently excluded from either the current tax provision or the deferred tax provision. If any item, such as the effect of establishing an NOL, were excluded from the calculation, the total tax expense would be higher or lower than the taxes calculated using a statutory rate.

Consistent with prior proceedings, the tax expense in this filing is equal to the income times the statutory tax rate. No items, including the credit related to the NOL, have been excluded. If the NOL had been excluded, the underlying deferred tax provision would have been higher thereby resulting in a total tax expense greater than the statutory rate.

g) Total tax expense was calculated using the methodology described in subparts (e) and (f). The impact of the Company's NOL has not been excluded on any schedules in the filing.

Respondent: Pace McDonald

EXHIBIT ____ (LK-12)

REQUEST:

Refer to page 19 of32 of the request for PLR included in Exhibit PM-l wherein it states:

"The type of ratemaking for the DT A claimed by the regulators in PLR 201418024 is not practiced (or even claimed to be practiced) by the regulators in Kentucky."

a. Please describe the party and the manner, and identify the forum, in which each such party would have "claimed" that the KPSC practiced the "type of ratemaking for the DTA claimed by the regulators in PLR 20 1418024," for both rate base and income tax. expense purposes. Provide a copy of all documentation relied on for your response.

b. Please provide a copy of PLR 201418024.

c. Please confi1m that the "rate making for the DT A claimed by the regulators in PLR 20 1418024" is described in that PLR as follows:

   i. Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed through to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer's plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of NOLCs or the AMT. Commission, in an order issued on Date C, did not use the mnounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as this case, an NOLC or AMT. Thus, Commission asse1is that it has already recognized the effects of the NOLC in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

d. Please confirm that the "ratemaking for the DTA" in KPSC Case No. 2013-00148 is identical to that claimed by the regulator in PLR 201418024, except that the KPSC used the DTA to reduce the DTL while the regulator in PLR 201418024 did not do so. If the Company cannot confi1m this, then please identify and describe all differences the Company believes exist, and in particular, all differences in the calculation of income tax expense, if any.

e. Please confirm that the KPSC reflected full income tax normalization in the income tax expense allowed in Case No. 2013-00148, meaning that it included the deferred income tax expense debit related to accelerated tax depreciation with no reduction for any deferred income tax expense credit related to an NOL. Cite to the Order and all other record evidence that supports your response.

f. Please confi1m that the regulators in PLR 201418024 did not reduce the DTL by the DTA related to the NOL and that the PLR found this was not a violation of the normalization requirements of the IRC or Treasury Regulations.

g. Please identify who drafted the referenced statement in the Atmos Request for PLR.

h. Please provide a copy of all support and analysis relied upon for the referenced statement in the Atmos Request for PLR.

i. Please indicate whether Mr. McDonald believes today that the referenced statement is accurate and correct with respect to the income tax expense allowed in Case No. 2013-00148. If so, then please provide all support and analysis relied upon to reach this conclusion. In addition, please provide all support relied upon to reach the conclusion that the deferred income tax expense allowed in Case No. 2013-00148 was reduced by a credit deferred income tax expense related to an NOL. Finally, provide all schedules that demonstrate and quantify the credit deferred income tax expense related to an NOL.

RESPONSE:

a. The type of ratemaking for deferred taxes and tax expense claimed by the regulators in PLR 201418024 would be presented in Kentucky in the form of a rate case. Atmos Energy is not aware of any case past or present in which the Kentucky PSC has ruled that balance of deferred taxes and tax provision should be calculated in a manner consistent with PLR 20148024.

b. See Attachment 1.

c. The section of PLR 201418024 cited above along with the following section cited below is the IRS summary of the ratemaking for the DTA claimed by the regulators in PLR 201418024:

"Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates."

d. The Company cannot confirm because the statement is incomplete. The ratemaking for tax provision and ADIT in KPSC Case No. 2013-00148 is not identical to that claimed by the regulator in PLR 201418024. The question as stated notes only one difference between PLR 201418024 and KPSC Case No. 2013-00148 when, in fact, there are two.

The first difference, as identified in the question, is in PLR 201418024 the Commission did not reduce the DTL by the NOLC DTA. However there is a second critical difference not noted as an exception in the question.

In setting the provision (or tax expense) for deferred taxes in the case, the Commission in PLR 201418024 took into account the entire difference between accelerated tax and regulatory depreciation. It did not adjust the deferred tax provision for the establishment of an NOLC DTA.

Unlike PLR 201418024, the provision for deferred taxes in KPSC 2013-00148 was impacted by both the entire difference between accelerated tax and regulatory depreciation AND the recording of an NOLC DTA. If the Company's NOLs had been excluded from the deferred tax provision, the Company's provision for income taxes would have been higher than a tax provision included in the filing.

This is a critical difference and central to why the IRS reached a different conclusion in the PLR issued to the Company.

e. The Company cannot confirm because the statement is incomplete. The Company did reflect full income tax normalization but the meaning of full income tax normalization as described in the question is incorrect. Full income tax normalization would result in a provision for income taxes which includes the debit (increase) related to accelerated tax depreciation AND a credit (decrease) related to the recording of an NOL. While not specifically addressed in the order, deferred income tax expense in KPSC Case No. 2013-00148 was calculated in this manner.

f. The Company cannot confirm because the statement is incomplete. In PLR 201418024, the IRS found the rate making as represented by the regulators was not in violation of the normalization requirements. This conclusion was reached because the regulators in that case represented that the NOL had already been taken into account by not reflecting its effect in the provision for deferred taxes and thereby necessarily recording a higher deferred tax provision than would have been the case had its effect been recognized. Since the NOL had been taken into account in this manner, it was permissible to not reduce the DTL by the NOLC DTA.

g. The Atmos Request for PLR was jointly drafted by Mr. James Warren of Miller Chevalier and Mr. Pace McDonald of Atmos Energy.

h. The support of the statement is the filing and resulting order received in KPSC Case No. 2013-00148. Furthermore, the Commission issued a letter dated December 15, 2014 to Atmos Energy in which it found the Atmos Request for PLR to be adequate and complete.

i. Mr. McDonald believes the statement to be correct.

The calculation of the tax provision in Case No. 2013-00148 was made with a composite tax rate of 38.9%. This rate is the combined federal and state rate. Applying a composite rate to the revenue requirement results in the accrual of all taxes that will be owed for the revenue requirement. It is the total tax burden regardless of whether it is currently paid or deferred to a future period. Since the composite rate accrues all taxes, including all deferred taxes, it therefore includes the deferred taxes associated with both accelerated depreciation and NOLs.

If the Company's NOLs had been excluded from the deferred tax provision, the Company's provision for income taxes would have been higher than a tax provision calculated using a composite tax rate.

<u>ATTACHMENT:</u>

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-22_Att1 - PLR 201418024.pdf, 7 Pages.

Respondent: Pace McDonald

Internal Revenue Service

Number: **201418024**
Release Date: 5/2/2014

Index Number: 167.22-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-133813-13

Date:
January 27, 2014

LEGEND:

Taxpayer =

Parent =

State =
Commission =
Year A =
Year B =
Year C =
Year D =
Year E =
X =
Y =
Date A =
Date B =
Date C =
Date D =
Date E =
Case =
Director =

Dear . :

This letter responds to the request, dated July 30, 2013, of Taxpayer for a ruling on whether the Commission's treatment of Taxpayer's Accumulated Deferred Income

Tax (ADIT) account balance in the context of a rate case is consistent with the requirements of the normalization provisions of the Internal Revenue Code.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State. It is wholly owned by Parent. Taxpayer distributes and sells natural gas to customers in State. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer takes accelerated depreciation where available and, for the period beginning in Year A and ending in Year E, Taxpayer has, in the aggregate, produced more net operating losses (NOL) than taxable income. After application of the carryback and carryforward rules, Taxpayer represents that it has net operating loss carryforward (NOLC), produced in Year C and Year E, of $X as of the end of Year E. The amount of claimed accelerated depreciation in Year C and Year E exceeded the amount of the NOLCs for those years. In Year D, Taxpayer produced regular taxable income as well as alternative minimum taxable income (AMTI); the regular taxable income was offset by the NOLCs from Year B and year C but could not offset the entire alternative minimum tax (AMT) liability due to the limitation in § 56(d). Taxpayer paid $Y of AMT in Year D and had a minimum tax credit carryforward (MTCC) as of the end of year E of $Y.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account and also maintains an offsetting series of entries that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC. With respect to the $Y AMT liability from Year D, Taxpayer carried that amount as an offset to the ADIT because the AMT increased the payment of tax.

Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer's plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of

NOLCs or the AMT. Commission, in an order issued on Date C, did not use the amounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as in this case, an NOLC or AMT. Thus, Commission asserts that it has already recognized the effects of the NOCL in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

Taxpayer requests that we rule as follows:

Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 55 of the Code imposes an alternative minimum tax on certain taxpayers, including corporations. Adjustments in computing alternative minimum taxable income are provided in § 56. Section 56(a)(1) provides for the treatment of depreciation in computing alternative minimum taxable income. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In the rate case at issue, Commission has excluded from the base to which the Taxpayer's rate of return is applied the reserve for deferred taxes, unmodified by the accounts which Taxpayer has designed to calculate the effects of the NOLCs and MTCC. There is little guidance on exactly how an NOLC or MTCC must be taken into account in calculating the reserve for deferred taxes under §§ 1.167(1)-1(h)(1)(iii) and 56(a)(1)(D). However, it is clear that both must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT) for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. In particular, while we accept as true for purposes of this ruling Commission's assertions that it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or AMT, we do not conclude that it has done so and those assertions are subject to verification on audit.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman
Senior Technician Reviewer, Branch 6
(Passthroughs & Special Industries)

cc:

EXHIBIT ____ (LK-13)

REQUEST:

Refer to Schedule E, Computation of State & Federal Income Tax.

a. Please confirm that by using Operating Income before Income Tax & Interest, the Company's methodology assumes full normalization for income tax expense. If the Company cannot confirm this, then provide a detailed explanation as to why this is not correct.

b. Please disaggregate the income tax expense included in the base year and in the test year as shown on Schedule E into current income tax expense and deferred income tax expense. Provide all supporting data, assumptions, and calculations, including all electronic workpapers with formulas intact.

RESPONSE:

a) Confirm.

b) Because the Company is in a taxable loss position and owes no current taxes, all tax expense in the filing is deferred income tax expense.

Respondent: Pace McDonald

EXHIBIT ____ (LK-14)

REQUEST:

Please provide a copy of the summary pages for all Cash Working Capital lead/lag studies submitted in other rate proceedings in other jurisdictions over the last five years and identify the states and case citations for each.

RESPONSE:

Please see the following summary of Cash Working Capital lead/lag studies Atmos Energy has submitted in jurisdictions other than Kentucky between CY 2010 and CY 2015. Please see Attachment 1 for the related summary pages from these studies.

Colorado	Docket No. 13AL-0496G Docket No. 14AL-0300G Docket No. 15AL-0299G
Mid-Tex	GUD 10170 (2012)
Tennessee	Docket No. 12-00064 Docket No. 14-00146
Virginia	Case No. PUE-2015-00119
West Texas	GUD 10174 (2012) 2013 Statement of Intent (city-level)

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-10_Att1 - Atmos Energy CWC Summary Pages.pdf, 12 Pages.

Respondent: Greg Waller

Schedule CWC1

Atmos Energy Corporation - Colorado Service Area
Cash-Basis Cash Working Capital Analysis
Test Year Ended December 31, 2012

Line No.	Description	Amount	CWC Factor	Cash Working Capital
	(a)	(b)	(c)	(d)
1	Gas Purchased	51,775,138	(0.029452)	(1,524,881)
2				
3	O&M Expense:			
4	Labor O&M	5,665,015	0.029014	164,365
5	Other O&M	8,134,548	0.007644	62,180
6				
7	Franchise Tax	2,711,555	(0.042082)	(114,108)
8	Sales Tax	3,172,923	(0.010932)	(34,686)
9				
10	State Income Tax	480,387	(0.017205)	(8,265)
11	Federal Income Tax	3,463,319	(0.017205)	(59,586)
12	Other Taxes	2,265,142	(0.555260)	(1,257,743)
13				
14	Total	$77,668,027		($2,772,724)

Schedule CWC1

Atmos Energy Corporation - Colorado Service Area
Cash-Basis Cash Working Capital Analysis
Test Year Ended December 31, 2013

Line No.	Description	Amount	CWC Factor	Cash Working Capital
	(a)	(b)	(c)	(d)
1	Gas Purchased	74,284,446	(0.030548)	(2,269,241)
2				
3	O&M Expense:			
4	Labor O&M	5,835,949	0.026411	154,133
5	Other O&M	9,947,637	(0.012000)	(119,372)
6				
7	Franchise Tax	3,041,301	(0.046082)	(140,149)
8	Sales Tax	3,507,592	(0.013808)	(48,433)
9				
10	State Income Tax	501,673	(0.020082)	(10,075)
11	Federal Income Tax	3,616,781	(0.020082)	(72,632)
12	Other Taxes	2,354,754	(0.564877)	(1,330,147)
13				
14	Total	$103,090,133		(3,835,915)

Schedule CWC1

Atmos Energy Corporation - Colorado Service Area
Cash-Basis Cash Working Capital Analysis
Test Year Ended December 31, 2014

Line No.	Description	Amount	CWC Factor	Cash Working Capital
	(a)	(b)	(c)	(d)
1	Gas Purchased	$ 76,248,824	(0.019726)	$(1,504,084)
2				
3	O&M Expense:			
4	Labor O&M	5,935,506	0.045205	268,315
5	Other O&M	8,624,556	0.039041	336,711
6				
7	Franchise Tax	3,484,729	(0.026301)	(91,652)
8	Sales Tax	4,043,314	(0.002712)	(10,965)
9				
10	State Income Tax	580,197	(0.008301)	(4,816)
11	Federal Income Tax	4,182,892	(0.008301)	(34,722)
12	Other Taxes	2,622,760	(0.585918)	(1,536,722)
13				
14	Total	$ 105,722,777		$(2,577,936)

Atmos Energy Corporation-Mid Tex
Cash Working Capital Lead/Lag Analysis
For Test Period Twelve Months Ended September 30, 2011

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	588,359,610	1,611,944	*Sch 2*	36.25	*Sch 3*	40.40	(4.15)	(6,688,880)
3	Upstream Gas	144,363,267	395,516	*Sch 2*	36.25	*Sch 3*	38.20	(1.95)	(771,256)
4	Total Gas Expense	732,722,877	2,007,460						
5									(7,460,136)
6	Operation and Maintenance Expense								
7	O&M, Labor	56,457,085	154,677	*Sch 2*	36.25	*Sch 4*	25.71	10.54	1,630,295
8	O&M, Non-Labor	96,063,392	263,187	*Sch 2*	36.25	*Sch 5*	28.73	7.52	1,979,169
9	Total O&M Expense	152,520,477	417,864						
10									3,609,464
11									
12	Taxes Other Than Income [1]								
13	Ad Valorem	21,129,326	57,889	*Sch 2*	36.25	*Sch 6*	213.50	(177.25)	(10,260,748)
14	Payroll Taxes	2,722,791	7,460	*Sch 2*	36.25	*Sch 6*	31.61	4.64	34,613
15	Local Gross Receipts Tax	28,034,548	76,807	*Sch 2*	36.25	*Sch 6*	99.24	(62.99)	(4,838,256)
16	Railroad Commission Fee	63,120	173	*Sch 2*	36.25	*Sch 6*	94.84	(58.59)	(10,132)
17									
18	Allocated Taxes-Shared Services								
19	Ad Valorem	278,713	764	*Sch 2*	36.25	*Sch 6*	213.50	(177.25)	(135,348)
20	Payroll Taxes	1,715,908	4,701	*Sch 2*	36.25	*Sch 6*	31.61	4.64	21,813
21	Total Taxes Other Than Income	53,944,406	147,793						
22									(15,188,058)
23	Franchise Tax/State Margin Tax	4,684,638	12,835	*Sch 2*	36.25	*Sch 7*	(47.00)	83.25	1,068,483
24									
25	Federal Income Tax								
26	Current Taxes	0	0	*Sch 2*	36.25	*Sch 8*	36.75	(0.50)	0
27									
28	Interest on Customer Deposits	26,170	72	*Sch 2*	36.25	*Sch 9*	331.83	(295.58)	(21,193)
29									
30	TOTAL	943,898,568	2,586,023						(17,991,440)

[1] Excludes DOT tax, State Gross Receipts Tax and Prepaid Local Gross Receipts Tax.

Tennessee Docket No. 12-00064

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended November 30, 2013

Line No.	Description (a)		Test Year Expenses (b)	Average Daily Expense (b) / 365 days (c)		Revenue Lag (d)		Expense Lag (e)	Net Lag (d) - (e) (f)	CWC Requirement (c) x (f) (g)
1	Gas Supply Expense									
2	Purchased Gas		69,266,324	189,771	*Sch 2*	36.48	*Sch 3*	39.46	(2.98)	(565,518)
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		7,362,569	20,171	*Sch 2*	36.48	*Sch 4*	14.14	22.34	450,620
6	O&M, Non-Labor		13,507,187	37,006	*Sch 2*	36.48	*Sch 5*	22.78	13.70	506,982
7	Total O&M Expense		20,869,756							957,602
8										
9										
10	Taxes Other Than Income									
11	Ad Valorem		3,318,150	9,091	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(1,863,837)
12	State Gross Receipts Tax		1,228,602	3,366	*Sch 2*	36.48	*Sch 6*	(151.50)	187.98	632,741
13	Payroll Taxes		280,781	769	*Sch 2*	36.48	*Sch 6*	19.19	17.29	13,298
14	Franchise Tax		602,000	1,649	*Sch 2*	36.48	*Sch 6*	37.00	(0.52)	(857)
15	TRA Inspection Fee		433,803	1,189	*Sch 2*	36.48	*Sch 6*	272.50	(236.02)	(280,628)
16	DOT		18,035	49	*Sch 2*	36.48	*Sch 6*	60.00	(23.52)	(1,152)
17										
18	Allocated Taxes-Shared Services									
19	Ad Valorem	21%	60,510	166	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(34,033)
20	Payroll Taxes	79%	227,633	624	*Sch 2*	36.48	*Sch 6*	19.19	17.29	10,791
21										
22	Allocated Taxes-Business Unit									
23	Ad Valorem	45%	42,039	115	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(23,577)
24	Payroll Taxes	55%	51,381	141	*Sch 2*	36.48	*Sch 6*	19.19	17.29	2,438
25	Total Taxes Other Than Income		6,262,934							(1,544,818)
26										
27	Federal Income Tax		*6,345,272*							
28	Current Taxes		1,938,704	5,312	*Sch 2*	36.48	*Sch 7*	37.00	(0.52)	(2,762)
29	Deferred Taxes		4,406,568	12,073	*Sch 2*	36.48	*Sch 7*	0.00	36.48	440,423
30										
31	State Excise Tax		*1,260,891*							
32	Current Taxes		385,246	1,055	*Sch 2*	36.48	*Sch 8*	37.00	(0.52)	(549)
33	Deferred Taxes		875,644	2,399	*Sch 2*	36.48	*Sch 8*	0.00	36.48	87,516
34										
35	Depreciation		10,620,298	29,097	*Sch 2*	36.48		0	36.48	1,061,459
36										
37	Interest on Customer Deposits		129,748	355	*Sch 2*	36.48		15.5	20.98	7,448
38										
39	Interest Expense - LTD		6,426,760	17,608	*Sch 2*	36.48	*Sch 9*	91.19	(54.71)	(963,251)
40										
41	Interest Expense - STD		41,732	114	*Sch 2*	36.48	*Sch 10*	24.05	12.43	1,417
42										
43	Return on Equity		11,760,772	32,221	*Sch 2*	36.48		0	36.48	1,175,422
44										
45										
46	TOTAL		132,984,486							652,972

Tennessee Docket No. 12-00064

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Test Year Ended March 31, 2012

Line No.	Description		Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)		(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense									
2	Purchased Gas		69,266,324	189,771	*Sch 2*	36.48	*Sch 3*	39.46	(2.98)	(565,517)
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		6,792,433	18,609	*Sch 2*	36.48	*Sch 4*	14.14	22.34	415,734
6	O&M, Non-Labor		10,521,682	28,827	*Sch 2*	36.48	*Sch 5*	22.78	13.70	394,923
7	Total O&M Expense		17,314,115							810,658
8										
9										
10	Taxes Other Than Income									
11	Ad Valorem		3,045,257	8,343	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(1,710,517)
12	State Gross Receipts Tax		1,554,329	4,258	*Sch 2*	36.48	*Sch 6*	(151.50)	187.98	800,501
13	Payroll Taxes		267,597	733	*Sch 2*	36.48	*Sch 6*	19.19	17.29	12,678
14	Franchise Tax		527,019	1,444	*Sch 2*	36.48	*Sch 6*	37.00	(0.52)	(751)
15	TRA Inspection Fee		460,103	1,261	*Sch 2*	36.48	*Sch 6*	272.50	(236.02)	(297,517)
16	DOT		36,570	100	*Sch 2*	36.48	*Sch 6*	60.00	(23.52)	(2,357)
17										
18	Allocated Taxes-Shared Services									
19	Ad Valorem	21%	54,203	149	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(30,445)
20	Payroll Taxes	79%	203,905	559	*Sch 2*	36.48	*Sch 6*	19.19	17.29	9,660
21										
22	Allocated Taxes-Business Unit									
23	Ad Valorem	45%	34,194	94	*Sch 2*	36.48	*Sch 6*	241.50	(205.02)	(19,207)
24	Payroll Taxes	55%	41,792	114	*Sch 2*	36.48	*Sch 6*	19.19	17.29	1,980
25	Total Taxes Other Than Income		6,224,968							(1,235,973)
26										
27	Federal Income Tax		*5,971,359*							
28	Current Taxes		2,841,794	7,786	*Sch 2*	36.48	*Sch 7*	37.00	(0.52)	(4,049)
29	Deferred Taxes		3,129,565	8,574	*Sch 2*	36.48	*Sch 7*	0.00	36.48	312,785
30										
31	State Excise Tax		*1,188,769*							
32	Current Taxes		565,740	1,550	*Sch 2*	36.48	*Sch 8*	37.00	(0.52)	(806)
33	Deferred Taxes		623,029	1,707	*Sch 2*	36.48	*Sch 8*	0.00	36.48	62,269
34										
35	Depreciation		10,216,011	27,989	*Sch 2*	36.48		0	36.48	1,021,041
36										
37	Interest on Customer Deposits		123,809	339	*Sch 2*	36.48		15.5	20.98	7,116
38										
39	Interest Expense - LTD		6,059,162	16,600	*Sch 2*	36.48	*Sch 10*	91.19	(54.71)	(908,133)
40										
41	Interest Expense - STD		39,345	108	*Sch 2*	36.48	*Sch 10*	24.05	12.43	1,343
42										
43	Return on Equity		11,086,445	30,374	*Sch 2*	36.48		0	36.48	1,108,037
44										
45										
46	TOTAL		127,490,307							607,429

Tennessee Docket No. 14-00146

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended May 31, 2016

Line No.	Description		Test Year Expenses	Average Daily Expense (b) / 366 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)		(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense									
2	Purchased Gas		87,478,439	239,012	*CWC2*	37.50	*CWC3*	39.33	(1.83)	(437,392)
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		7,915,572	21,627	*CWC2*	37.50	*CWC4*	14.07	23.43	506,721
6	O&M, Non-Labor		12,100,932	33,063	*CWC2*	37.50	*CWC5*	29.40	8.10	267,810
7	Total O&M Expense		20,016,504							774,531
8										
9										
10	Taxes Other Than Income									
11	Ad Valorem		3,801,021	10,385	*CWC2*	37.50	*CWC6*	241.50	(204.00)	(2,118,540)
12	State Gross Receipts Tax		1,241,962	3,393	*CWC2*	37.50	*CWC6*	(151.50)	189.00	641,277
13	Payroll Taxes		272,080	743	*CWC2*	37.50	*CWC6*	16.55	20.95	15,569
14	Franchise Tax		622,004	1,699	*CWC2*	37.50	*CWC6*	37.50	0.00	0
15	TRA Inspection Fee		530,084	1,448	*CWC2*	37.50	*CWC6*	272.50	(235.00)	(340,280)
16	DOT		0	0	*CWC2*	37.50	*CWC6*	59.00	(21.50)	0
17										
18	Allocated Taxes-Shared Services									
19	Ad Valorem	16%	49,974	137	*CWC2*	37.50	*CWC6*	241.50	(204.00)	(27,948)
20	Payroll Taxes	84%	255,485	698	*CWC2*	37.50	*CWC6*	16.55	20.95	14,626
21										
22	Allocated Taxes-Business Unit									
23	Ad Valorem	46%	48,815	133	*CWC2*	37.50	*CWC6*	241.50	(204.00)	(27,132)
24	Payroll Taxes	54%	57,959	158	*CWC2*	37.50	*CWC6*	16.55	20.95	3,311
25	Total Taxes Other Than Income		6,879,384							(1,839,117)
26										
27	Federal Income Tax		*8,128,108*							
28	Current Taxes		2,864,727	7,827	*CWC2*	37.50	*CWC7*	37.50	0.00	0
29	Deferred Taxes		5,263,381	14,381	*CWC2*	37.50	*CWC7*	0.00	37.50	539,288
30										
31	State Excise Tax		*1,614,444*							
32	Current Taxes		569,006	1,555	*CWC2*	37.50	*CWC8*	37.50	0.00	0
33	Deferred Taxes		1,045,438	2,856	*CWC2*	37.50	*CWC8*	0.00	37.50	107,100
34										
35	Depreciation		12,468,039	34,066	*CWC2*	37.50		0	37.50	1,277,475
36										
37	Interest on Customer Deposits		118,049	323	*CWC2*	37.50		182.5	(145.00)	(46,835)
38										
39	Interest Expense - LTD		6,623,097	18,096	*CWC2*	37.50	*CWC9*	91.25	(53.75)	(972,660)
40										
41	Return on Equity		15,166,903	41,440	*CWC2*	37.50		0	37.50	1,554,000
42										
43										
44	TOTAL		158,492,968							956,389

Tennessee Docket No. 14-00146

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Test Year Ended June 30, 2014

Line No.	Description		Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)		(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense									
2	Purchased Gas		87,478,439	239,667	*CWC2*	37.50	*Sch 3*	39.33	(1.83)	(438,591)
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		7,652,390	20,965	*CWC2*	37.50	*Sch 4*	14.07	23.43	491,221
6	O&M, Non-Labor		12,983,102	35,570	*CWC2*	37.50	*Sch 5*	29.40	8.10	288,118
7	Total O&M Expense		20,635,493							779,339
8										
9										
10	Taxes Other Than Income									
11	Ad Valorem		3,498,394	9,585	*CWC2*	37.50	*CWC6*	241.50	(204.00)	(1,955,267)
12	State Gross Receipts Tax		1,084,335	2,971	*CWC2*	37.50	*CWC6*	(151.50)	189.00	561,478
13	Payroll Taxes		257,296	705	*CWC2*	37.50	*CWC6*	16.55	20.95	14,771
14	Franchise Tax		618,254	1,694	*CWC2*	37.50	*CWC6*	37.50	0.00	0
15	TRA Inspection Fee		425,046	1,165	*CWC2*	37.50	*CWC6*	272.50	(235.00)	(273,660)
16	DOT		19,392	53	*CWC2*	37.50	*CWC6*	59.00	(21.50)	(1,142)
17										
18	Allocated Taxes-Shared Services									
19	Ad Valorem	0%	0	0	*CWC2*	37.50	*CWC6*	241.50	(204.00)	0
20	Payroll Taxes	100%	247,649	678	*CWC2*	37.50	*CWC6*	16.55	20.95	14,217
21										
22	Allocated Taxes-Business Unit									
23	Ad Valorem	10%	6,231	17	*CWC2*	37.50	*CWC6*	241.50	(204.00)	(3,482)
24	Payroll Taxes	90%	55,697	153	*CWC2*	37.50	*CWC6*	16.55	20.95	3,198
25	Total Taxes Other Than Income		6,212,295							(1,639,888)
26										
27	Federal Income Tax		*7,465,832*							
28	Current Taxes		0	0	*CWC2*	37.50	*CWC7*	37.50	0.00	0
29	Deferred Taxes		7,465,832	20,454	*CWC2*	37.50	*CWC7*	0.00	37.50	767,038
30										
31	State Excise Tax		*1,483,046*							
32	Current Taxes		0	0	*CWC2*	37.50	*CWC8*	37.50	0.00	0
33	Deferred Taxes		1,483,046	4,063	*CWC2*	37.50	*CWC8*	0.00	37.50	152,368
34										
35	Depreciation		10,700,686	29,317	*CWC2*	37.50		0	37.50	1,099,386
36										
37	Interest on Customer Deposits		110,242	302	*CWC2*	37.50		182.5	(145.00)	(43,795)
38										
39	Interest Expense - LTD		6,084,048	16,669	*CWC2*	37.50	*CWC9*	91.25	(53.75)	(895,939)
40										
41	Return on Equity		13,927,092	38,156	*CWC2*	37.50		0	37.50	1,430,866
42										
43										
44	TOTAL		154,097,173							1,210,783

Virginia Case No. PUE-2015-00119

Atmos Energy Corporation-Virginia
Lead / Lag Cash Working Capital Calculation - Total Company Per Books (GAAP)
TME: September 30, 2015
Case No. PUE-2015-00119

Line No.	Cost Category (1)	Per Books Expense (2)	Daily Amount (3)=(2)/365	Rev Lag Days (4)	Expense Lead Days (5)	Reference (6)	Net Lag Days (7)=(4)-(5)	Working Capital Req. (8)=(3)*(7)
1	OPERATING EXPENSES:							
2	Purchased Gas Expense	$ 1,043,550,773	$ 2,859,043	40.93	39.63	Sheet 4	1.30	$ 3,706,847
3	Deferred Gas Expense	(63,125,790)	(172,947)	40.93	40.93	Note 3	0.00	-
4	Stored Gas Expense	48,197,347	132,048	40.93	0.00	Note 1	40.93	5,404,725
5	Prepaid Insurance Expense	12,457,311	34,130	40.93	0.00	Note 1	40.93	1,396,941
6	Payroll Costs	178,828,231	489,940	40.93	14.10	Sheet 5	26.83	13,145,090
7	Employee Benefits Expense	35,591,227	97,510	40.93	0.00	Note 1	40.93	3,991,084
8	Incentive Compensation Exp	34,408,040	94,269	40.93	0.00	Note 1	40.93	3,858,430
9	Pension and RIP Expense	25,899,122	70,956	40.93	0.00	Note 1	40.93	2,904,229
10	OPEB Expense	12,871,162	35,263	40.93	63.41	Sheet 6	(22.48)	(792,676)
11	Other O & M Costs:							
12	Accrued Vacation	(4,370,892)	(11,975)	40.93	0.00	Note 1	40.93	(490,137)
13	Uncollectible Expense	15,904,325	43,573	40.93	459.53	Sheet 7	(418.60)	(18,239,459)
14	Injuries and Damage Expense	26,254,702	71,931	40.93	0.00	Note 1	40.93	2,944,136
15	Other	181,279,089	496,655	40.93	36.70	Sheet 8	4.23	2,100,851
16	Depreciation and Amort Exp	281,102,498	770,144	40.93	0.00	Note 1	40.93	31,521,994
17								
18	TAXES OTHER THAN INCOME:							
19	Payroll Tax Expense	13,874,044	38,011	40.93	19.25	Sheet 9	21.68	824,032
20	Property Tax Expense	93,719,214	256,765	40.93	100.03	Sheet 10	(59.10)	(15,175,930)
21	Other Taxes	123,369,844	337,999	40.93	31.96	Sheet 11	8.97	3,032,213
22	TOTAL OPERATING EXP & OTH TAX	2,059,810,047						
23	INCOME TAXES:							
24	Current (Including state)	(9,898,087)	(27,118)	40.93	37.50	Sheet 12	3.43	(93,015)
25	Deferred FIT Included in RB	194,351,594	532,470	40.93	0.00	Note 1	40.93	21,793,997
26	TOTAL INCOME TAX EXP	184,453,507						
27	OTHER EXPENSES:							
28	Charitable Donations	3,456,343	9,469	40.93	40.93	Note 2	0.00	-
29	Interest on Customer Deposits	665,843	1,824	40.93	182.50	Sheet 13	(141.57)	(258,224)
30	Interest Expense on LT Debt	144,874,613	396,917	40.93	91.25	Sheet 14	(50.32)	(19,972,863)
31	AFUDC	(2,374,770)	(6,506)	40.93	40.93	Note 2	0.00	-
32	Other Income	(14,974,677)	(41,027)	40.93	40.93	Note 2	0.00	-
33	TOTAL OTHER INCOME	131,647,153						
34	Income Avail for Common Eq	299,475,209	820,480	40.93	40.93	Note 2	0.00	-
35	Subtotal		-					41,602,265
36	Customer Utility Taxes	707,783	1,939	40.93	27.76	Sheet 15	13.17	25,537
37	State & Local Consumption Taxes	366,594	1,004	40.93	32.71	Sheet 16	8.22	8,248
38	Plus: Balance Sheet Analysis					Schedule 28		(374,367)
39	TOTAL CASH WORKING CAPITAL REQUIREMENT/(SOURCE)							41,261,683

Note 5: 0 Net Lead days assigned in compliance with Staff Report
Note 1: Item is included in the Balance Sheet Analysis; therefore, 0 lead days assigned.
Note 2: 0 Net Lead days assigned in compliance with the Staff in Case No. PUE950033.
Note 3: Per Case No. PUE950033, 0 Cash Working Capital used due to a timing difference between deferred gas expense and the average defer

Virginia Case No. PUE-2015-00119

Exhibit No. GKW3
Witness: Waller
Schedule 27
Sheet 2a

Atmos Energy Corporation-Virginia
Lead / Lag Cash Working Capital Calculation - Jurisdictional Per Books (GAAP)
TME: September 30, 2015
Case No. PUE-2015-00119

Line No.	Cost Category (1)	Alloc Factor Ref (2)	Alloc Factor % (3)	Jurisdictional Per Books Expense (4)	Allocated Per Books Expense (5)=(3)*(4)	Juris. Daily Amount (6)=(5)/365	Rev Lag Days (7)	Expense Lead Days (8)	Ref (9)	Net Lag Days (10)=(7)-(8)	Jurisdictional CWC Requirement (11)=(10)*(6)
1	**OPERATING EXPENSES:**										
2	Purchased Gas Expense	WP 40-1 "V"	90.270%	$ 23,490,569	$21,204,936	$ 58,096	40.93	39.63	Sheet 4	1.30	$ 75,323
3	Deferred Gas Expense	WP 40-1 "V"	90.270%	-	-	-	40.93	40.93	Note 3	0.00	-
4	Stored Gas Expense	WP 40-1 "AA"	86.980%	844,857	734,856	2,013	40.93	0.00	Note 1	40.93	82,392
5	Prepaid Insurance Expense	WP 40-1 "V"	90.270%	5,238	4,728	13	40.93	0.00	Note 1	40.93	532
6	Payroll costs	WP 40-1 "V"	90.270%	976,858	881,809	2,416	40.93	14.10	Sheet 5	26.83	64,821
7	Employee Benefits Expense	WP 40-1 "V"	90.270%	226,415	204,385	560	40.93	0.00	Note 1	40.93	22,921
8	Incentive Compensation	WP 40-1 "S"	89.880%	144,593	129,960	356	40.93	0.00	Note 1	40.93	14,571
9	Pension and RIP expense	WP 40-1 "V"	90.270%	84,239	76,043	208	40.93	0.00	Note 1	40.93	8,513
10	OPEB expense	WP 40-1 "V"	90.270%	121,932	110,068	302	40.93	63.41	Sheet 6	(22.48)	(6,789)
11	Other O & M Costs:										
12	Accrued Vacation	WP 40-1 "V"	90.270%	(411,103)	(371,103)	(1,017)	40.93	0.00	Note 1	40.93	(41,626)
13	Uncollectible Expense	WP 40-1 "V"	90.270%	115,921	104,642	287	40.93	459.53	Sheet 7	(418.60)	(120,137)
14	Injuries and Damage Expense	WP 40-1 "V"	90.270%	3,418	3,086	8	40.93	0.00	Note 1	40.93	327
15	Other	WP 40-1 "V"	90.270%	804,089	725,851	1,989	40.93	36.70	Sheet 8	4.23	8,413
16	Depreciation and Amort Exp	WP 40-1 "V"	90.270%	2,300,769	2,076,904	5,690	40.93	0.00	Note 1	40.93	232,892
17											
18	**TAXES OTHER THAN INCOME**										
19	Payroll Tax Expense	WP 40-1 "V"	90.270%	130,025	117,373	322	40.93	19.25	Sheet 9	21.68	6,981
20	Property Tax Expense	WP 40-1 "V"	90.270%	456,800	412,353	1,130	40.93	100.03	Sheet 10	(59.10)	(66,788)
21	Other Taxes	WP 40-1 "V"	90.270%	92,692	83,673	229	40.93	31.96	Sheet 11	8.97	2,054
22	TOTAL OPERATING EXP	WP 40-1 "V"	90.270%	29,387,311		72,602					
23	**INCOME TAXES:**										
24	Current (including state)	WP 40-1 "AE"	88.630%	2,830,952	2,509,073	6,874	40.93	37.50	Sheet 12	3.43	23,578
25	Deferred FIT Included in RB	WP 40-1 "AE"	88.630%	(430,209)	(381,294)	(1,045)	40.93	0.00	Note 1	40.93	(42,772)
26	TOTAL INCOME TAX EXP			2,400,743	-	5,829					
27	**OTHER EXPENSES:**										
28	Charitable Donations		100.000%	16,913	16,913	46	40.93	40.93	Note 2	0.00	-
29	Interest on Customer Deposits	WP 40-1 "F"	96.820%	559	541	1	40.93	182.50	Sheet 13	(141.57)	(142)
30	Interest Expense on LT Debt	WP 40-1 "V"	90.270%	1,032,753	932,266	2,554	40.93	91.25	Sheet 14	(50.32)	(128,517)
31	AFUDC	WP 40-1 "V"	90.270%	206	186	1	40.93	40.93	Note 2	0.00	-
33	TOTAL OTHER INCOME			1,050,431		2,602					
34	Income Avail for Common Eq	Sch 40b; p. 1		4,677,085		12,814	40.93	40.93	Note 2	0.00	-
35	Subtotal			42,192,655		93,847					136,547
36	Customer Utility Taxes	WP 40-1 "V"	90.270%	707,783		1,939	40.93	27.76	Sheet 15	13.17	25,537
37	State & Local Consumption Taxes	WP 40-1 "V"	90.270%	366,594		1,004	40.93	32.71	Sheet 16	8.22	8,248
38	Plus: Balance Sheet Analysis	Sch 28							Schedule 28		(338,127)
39						TOTAL CASH WORKING CAPITAL REQUIREMENT/(SOURCE)					$ (167,795)

Note 1: Item is included in the Balance Sheet Analysis; therefore, 0 lead days assigned.
Note 2: 0 Net Lead days assigned in compliance with the Staff in Case No. PUE950033
Note 3: Per Case No. PUE950033, 0 Cash Working Capital used due to a timing difference.

THP-CWC1

Atmos Energy Corporation - West Texas
Cash Working Capital Lead/ Lag Analysis
For Test Period Twelve Months Ended September 30, 2011

Line No.	Description	Test Year Expenses	Average Daily Expense	Revenue Lag Ref.	Revenue Lag Days	Expense Lag Ref.	Expense Lag Days	Net Lag	CWC Requiremen
	(a)	(b)	(c) = (b)/365		(d)		(e)	(f) = (d) - (e)	(g) = (c) x (f)
1	Gas Supply Expense								
2	Purchased Gas	137,507,303	376,732	*CWC 2*	39.03	*CWC3*	41.41	(2.38)	(896,623)
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	11,585,306	31,741	*CWC 2*	39.03	*CWC 4*	28.22	10.81	343,115
6	O&M, Non-Labor	21,695,928	59,441	*CWC 2*	39.03	*CWC 5*	32.80	6.23	370,317
7	Total O&M Expense	33,281,234	91,181						713,432
8									
9									
10	Taxes Other Than Income [1]								
11	Ad Valorem	3,659,051	10,025	*CWC 2*	39.03	*CWC 6*	213.50	(174.47)	(1,749,027)
12	Payroll Taxes	534,370	1,464	*CWC 2*	39.03	*CWC 6*	33.96	5.07	7,423
13	Local Franchise Tax	2,868,088	7,858	*CWC 2*	39.03	*CWC 6*	66.28	(27.25)	(214,104)
14	State Gas Transportation	1,576	4	*CWC 2*	39.03	*CWC 6*	94.69	(55.66)	(240)
15									
16	Allocated Taxes								
17	Ad Valorem	79,904	219	*CWC 2*	39.03	*CWC 6*	213.50	(174.47)	(38,194)
18	Payroll Taxes	348,509	955	*CWC 2*	39.03	*CWC 6*	33.96	5.07	4,841
19	Total Taxes Other Than Income	7,491,498	20,525						(1,989,302)
20									
21	Franchise Tax/State Margin Tax	933,185	2,557	*CWC 2*	39.03	*CWC 7*	(47.00)	86.03	219,950
22									
23	Federal Income Tax								
24	Current Taxes	0	0	*CWC 2*	39.03	*CWC 8*	36.75	2.28	0
25									
26	Interest on Customer Deposits	6,115	17	*CWC 2*	39.03	*CWC 9*	331.83	(292.80)	(4,905)
27									
28	TOTAL	179,219,334	491,012						(1,957,448)

[1] Excludes DOT tax and State Gross Receipts Tax.

THP-CWC1

Atmos Energy Corporation - West Texas
Cash Working Capital Lead/ Lag Analysis
For Test Period Twelve Months Ended June 30, 2013

Line No.	Description	Test Year Expenses	Average Daily Expense	Revenue Lag Ref.	Revenue Lag Days	Expense Lag Ref.	Expense Lag Days	Net Lag	CWC Requiremen
	(a)	(b)	(c) = (b)/365		(d)		(e)	(f) = (d) - (e)	(g) = (c) x (f)
1	Gas Supply Expense								
2	Purchased Gas	115,600,453	316,714	*CWC 2*	38.54	*CWC3*	41.65	(3.11)	(984,979)
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	11,904,423	32,615	*CWC 2*	38.54	*CWC 4*	29.29	9.25	301,687
6	O&M, Non-Labor	22,671,849	62,115	*CWC 2*	38.54	*CWC 5*	33.37	5.17	321,133
7	Total O&M Expense	34,576,272	94,730						622,820
8									
9									
10	Taxes Other Than Income [1]								
11	Ad Valorem	4,133,461	11,325	*CWC 2*	38.54	*CWC 6*	213.50	(174.96)	(1,981,344)
12	Payroll Taxes	474,451	1,300	*CWC 2*	38.54	*CWC 6*	34.49	4.05	5,264
13	Allocated Taxes								
14	Ad Valorem and other	89,188	244	*CWC 2*	38.54	*CWC 6*	213.50	(174.96)	(42,752)
15	Payroll Taxes	509,122	1,395	*CWC 2*	38.54	*CWC 6*	34.49	4.05	5,649
16	Total Taxes Other Than Income	5,206,223	14,264						(2,013,182)
17									
18	Revenue Taxes [1]								
19	Local Franchise Tax	8,536,899	23,389	*CWC 2*	38.54	*CWC 6*	65.68	(27.14)	(634,833)
20	State Gas Transportation	1,762	5	*CWC 2*	38.54	*CWC 6*	94.73	(56.19)	(271)
21									
22	State Gross Margin Tax	1,000,916	2,742	*CWC 2*	38.54	*CWC 7*	(46.50)	85.04	233,200
23									
24	Federal Income Tax								
25	Current Taxes	8,736,560	23,936	*CWC 2*	38.54	*CWC 8*	37.50	1.04	24,893
26									
27	Interest on Customer Deposits	5,432	15	*CWC 2*	38.54	*CWC 9*	331.83	(293.29)	(4,365)
28									
29	TOTAL	173,664,518	452,400						(2,756,717)

[1] Excludes DOT tax and State Gross Receipts Tax.

EXHIBIT ____ (LK-15)

Atmos Energy Corporation - Kentucky Division
Cost of Capital - With AG Recommended Adjustments
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017

I. Atmos Cost of Capital Per Filing

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	415,876	6.47%	0.94%	0.06%	0.06%
Long Term Debt	2,455,780	38.21%	5.90%	2.25%	2.25%
Common Equity	3,554,717	55.32%	10.50%	5.81%	9.58%
Total Capital	6,426,373	100.00%		8.12%	11.89%

II. Atmos Cost of Capital Adjusted to Include AG Adjustments to Capital Structure

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	565,376	8.80%	0.94%	0.08%	0.08%
Long Term Debt	2,455,780	38.21%	5.90%	2.25%	2.25%
Common Equity	3,405,217	52.99%	10.50%	5.56%	9.16%
Total Capital	6,426,373	100.00%		7.89%	11.49%
Change in Grossed Up Weighted Avg Cost of Capital					-0.39%
Rate Base Recommended by AG					294,202,371
Revenue Requirement Effect of Adjustment					(1,153,299)

III. Atmos Cost of Capital Adjusted to Reflect Lower Short Term Debt Rate by Removal of AEC Commitment and Banking Fees

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	565,376	8.80%	0.40%	0.03%	0.03%
Long Term Debt	2,455,780	38.21%	5.90%	2.25%	2.25%
Common Equity	3,405,217	52.99%	10.50%	5.56%	9.16%
Total Capital	6,426,373	100.00%		7.84%	11.44%
Change in Grossed Up Weighted Avg Cost of Capital					-0.05%
Rate Base Recommended by AG					294,202,371
Revenue Requirement Effect of Adjustment					(147,101)

Atmos Energy Corporation - Kentucky Division
Cost of Capital - With AG Recommended Adjustments
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017

IV. Atmos Cost of Capital Adjusted to Include AG Recommended ROE of 9.0%

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	565,376	8.80%	0.40%	0.03%	0.03%
Long Term Debt	2,455,780	38.21%	5.90%	2.25%	2.25%
Common Equity	3,405,217	52.99%	9.00%	4.77%	7.86%
Total Capital	6,426,373	100.00%		7.05%	10.14%
Change in Grossed Up Weighted Avg Cost of Capital					-1.30%
Rate Base Recommended by AG					294,202,371
Revenue Requirement Effect of Adjustment					(3,830,361)
Every 1% ROE Change					(2,553,574)

V. Atmos Cost of Capital Adjusted to Reflect As-Filed Capital Structure and AG Recommended ROE of 8.75%

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	415,876	6.47%	0.40%	0.03%	0.03%
Long Term Debt	2,455,780	38.21%	5.90%	2.25%	2.25%
Common Equity	3,554,717	55.32%	8.75%	4.84%	7.98%
Total Capital	6,426,373	100.00%		7.12%	10.26%
Change in Grossed Up Weighted Avg Cost of Capital					-1.60%
Rate Base Recommended by AG					294,202,371
Revenue Requirement Effect of Adjustment					(4,703,101)
Every 1% ROE Change					(2,687,486)

EXHIBIT ____ (LK-16)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Base Period: Twelve Months Ended February 29, 2016
Forecasted Test Period: Twelve Months Ended May 31, 2017

Allocation Factors

		Forecast Period			Base Period		
Line No.	Description	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite
	Rate Base, Dep. Exp., & Taxes Other						
1	**Shared Services**						
2	General Office (Div 002)	10.71%	49.09%	5.26%	10.71%	49.09%	5.26%
3	Customer Support (Div 012)	10.86%	52.60%	5.71%	10.86%	52.60%	5.71%
4	**Kentucky/Mid-States**						
5	Mid-States General Office (Div 091)	100%	49.09%	49.09%	100%	49.09%	49.09%
6							
7							
8	**Greenville Avenue Data Center**			1.54%			1.54%
9	**Charles K. Vaughan Center**			1.08%			1.08%
10							
11	**Kentucky Composite Tax**			38.90%			
12							
13	**Rate of Return on Equity**			10.50%			
14							
15	**STDRATE**			0.94%			
16							
17	**LTDRATE**			5.90%			

ATMOS ENERGY CORPORATION

Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/14

ALL COMPANIES			30 TATXF	60 TACOF	20 TALAF	20 TALAF	50 TAMIF	70 TAMSF	80 TATUF	180 TATPF	212 TAEMF	232 TASTF	233 TAWGF	303 TATLF	234 has the highest remaining Remainder TAPSF
A. Composite Allocation Factor:		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	Atmos P/L	AEM	UCG Storage	WKG Storage	TLGP	Remaining non reg
Gross Direct PP&E	$	8,527,002,426	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	3,393,212,543	1,757,100,641	36,175,456	8,579,774	14,517,166	24,532,139	10,958,332
Average Number of Customers	#	3,061,941	299,553	243,084	74,693	272,260	332,626	250,173	1,588,126	347	1,064			15	-
Total O&M Expense * (* w/o Allocation)	$	373,655,056	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	109,826,806	81,576,653	24,247,740	512,520	758,107	1,132,882	(2,162,819)
Total Composite Factor															
Gross Direct PP&E	%	100.00%	6.91%	6.13%	2.31%	6.24%	11.10%	5.80%	39.79%	20.61%	0.42%	0.10%	0.17%	0.29%	0.13%
Average Number of Customers	%	100.00%	9.79%	7.94%	2.44%	8.89%	10.86%	8.17%	51.87%	0.01%	0.03%	0.00%	0.00%	0.00%	0.00%
Total O&M Expense	%	100.00%	8.05%	6.68%	2.34%	6.04%	10.17%	8.95%	29.39%	21.83%	6.49%	0.14%	0.20%	0.30%	-0.58%
Total Composite Factor for FY 2015	%	100.00%	8.25%	6.92%	2.36%	7.06%	10.71%	7.64%	40.35%	14.15%	2.31%	0.08%	0.12%	0.20%	-0.15%

UTILITY ONLY			CUTXU	CUCKU	CULAU	CULAU	CUMIU	CUMSU	CUMTU
Gross Direct PP&E	$	6,675,138,918	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	3,393,212,543
Average Number of Customers	#	3,060,515	299,553	243,084	74,693	272,260	332,626	250,173	1,588,126
Total O&M Expense * (* w/o Allocation)	$	267,589,973	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	109,826,806
Gross Direct PP&E	%	100.00%	8.82%	7.83%	2.95%	7.97%	14.19%	7.41%	50.83%
Average Number of Customers	%	100.00%	9.79%	7.94%	2.44%	8.90%	10.87%	8.17%	51.89%
Total O&M Expense	%	100.00%	11.23%	9.33%	3.27%	8.44%	14.20%	12.49%	41.04%
Total Composite Factor for FY 2015	%	100.00%	9.93%	8.37%	2.89%	8.44%	13.09%	9.36%	47.92%

CUSTOMER			SEATX CCTXR	SEACO CCCKR	SEALA CCLAR	SEALA CCLAR	SEAMI CCMIR	SEAMS CCMSR	SEATU CCMTR	SEAPL
Average Number of Customers	%	100.00%	9.80%	7.94%	2.44%	8.89%	10.87%	8.17%	51.88%	0.01%

REGULATED ONLY			TUTXF	TUCOF	TULAF	TULAF	TUMIF	TUMSF	TUTUF	TUTPF
Gross Direct PP&E	$	8,432,239,559	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	3,393,212,543	1,757,100,641
Average Number of Customers	#	3,060,862	299,553	243,084	74,693	272,260	332,626	250,173	1,588,126	347
Total O&M Expense * (* w/o Allocation)	$	349,166,626	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	109,826,806	81,576,653
Gross Direct PP&E	%	100.00%	6.98%	6.20%	2.33%	6.31%	11.23%	5.87%	40.24%	20.84%
Average Number of Customers	%	100.00%	9.80%	7.94%	2.44%	8.89%	10.87%	8.17%	51.88%	0.01%
Total O&M Expense	%	100.00%	8.61%	7.15%	2.51%	6.47%	10.88%	9.57%	31.45%	23.36%
Total Composite Factor for FY 2015	%	100.00%	8.46%	7.10%	2.43%	7.22%	10.99%	7.87%	41.19%	14.74%

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/14

234 has the highest remaining

REGULATED AND 303 (TLGP)			30 CUTXT	60 CUCKT	20 CULAT	20 CULAT	50 CUMIT	70 CUMST	80 CUMTT	180 CUTPT	212	232	233	503 CUGPT	Remainder
Gross Direct PP&E	$	8,456,771,698	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	3,393,212,543	1,757,100,641				24,532,139	
Average Number of Customers	#	3,060,877	299,553	243,084	74,693	272,260	332,626	250,173	1,588,126	347				15	
Total O&M Expense *	$	350,299,508	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	109,826,806	81,576,653				1,132,882	
(* w/o Allocation)															
Gross Direct PP&E	%	100.00%	6.96%	6.18%	2.33%	6.29%	11.20%	5.85%	40.12%	20.78%				0.29%	
Average Number of Customers	%	100.00%	9.80%	7.94%	2.44%	8.89%	10.87%	8.17%	51.88%	0.01%				0.00%	
Total O&M Expense	%	100.00%	8.57%	7.13%	2.50%	6.45%	10.85%	9.54%	31.35%	23.29%				0.32%	
Total Composite Factor for FY 2015	%	100.00%	8.46%	7.08%	2.42%	7.21%	10.97%	7.85%	41.12%	14.69%				0.20%	

WT MS COKS			CGTXR	CGCKR				CGMSR		
Gross Direct PP&E	$	1,606,198,342	588,658,574	522,666,022				494,873,746		
Average Number of Customers	#	792,810	299,553	243,084				250,173		
Total O&M Expense *	$	88,417,950	30,013,523	24,974,685				33,429,741		
(* w/o Allocation)										
Gross Direct PP&E	%	100.00%	36.65%	32.54%	0.00%	0.00%	0.00%	30.81%	0.00%	0.00%
Average Number of Customers	%	100.00%	37.78%	30.66%	0.00%	0.00%	0.00%	31.56%	0.00%	0.00%
Total O&M Expense	%	100.00%	33.94%	28.25%	0.00%	0.00%	0.00%	37.81%	0.00%	0.00%
Total Composite Factor for FY 2015	%	100.00%	36.13%	30.48%	0.00%	0.00%	0.00%	33.39%	0.00%	0.00%

LA					LAA07	LAA77				
Gross Direct PP&E	$	728,851,252			196,802,776	532,048,476				
Average Number of Customers	#	346,953			74,693	272,260				
Total O&M Expense *	$	31,341,012			8,753,909	22,587,103				
(* w/o Allocation)										
Gross Direct PP&E	%	100.00%	0.00%	0.00%	27.00%	73.00%	0.00%	0.00%	0.00%	0.00%
Average Number of Customers	%	100.00%	0.00%	0.00%	21.53%	78.47%	0.00%	0.00%	0.00%	0.00%
Total O&M Expense	%	100.00%	0.00%	0.00%	27.93%	72.07%	0.00%	0.00%	0.00%	0.00%
Total Composite Factor for FY 2015	%	100.00%	0.00%	0.00%	25.49%	74.51%	0.00%	0.00%	0.00%	0.00%

Atmos 6			CUTXR	CUCKR	CULAR	CULAR	CUMIR	CUMSR		
Gross Direct PP&E	$	3,281,926,376	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746		
Average Number of Customers	#	1,472,389	299,553	243,084	74,693	272,260	332,626	250,173		
Total O&M Expense *	$	157,763,167	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741		
(* w/o Allocation)										
Gross Direct PP&E	%	100.00%	17.93%	15.93%	6.00%	16.21%	28.85%	15.08%		
Average Number of Customers	%	100.00%	20.35%	16.51%	5.07%	18.49%	22.59%	16.99%		
Total O&M Expense	%	100.00%	19.02%	15.83%	5.55%	14.32%	24.09%	21.19%		
Total Composite Factor for FY 2015	%	100.00%	19.10%	16.09%	5.54%	16.34%	25.18%	17.75%		

Texas only			TXONW						TXONM	TXONP
Gross Direct PP&E	$	5,738,971,758	588,658,574						3,393,212,543	1,757,100,641
Average Number of Customers	#	1,888,025	299,553						1,588,126	347
Total O&M Expense *	$	221,416,982	30,013,523						109,826,806	81,576,653
(* w/o Allocation)										
Gross Direct PP&E	%	100.00%	10.25%						59.13%	30.62%
Average Number of Customers	%	100.00%	15.86%						84.12%	0.02%
Total O&M Expense	%	100.00%	13.56%						49.60%	36.84%
Total Composite Factor for FY 2015	%	100.00%	13.23%						64.28%	22.49%

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/14

234 has the highest remaining Remainder

WEST TEXAS and MID TEX

		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	180	212	232	233	303
			30	60	20	20	50	70	80					
			TXWTR						TXMTR					
Gross Direct PP&E	$	3,981,871,117	588,658,574						3,393,212,543					
Average Number of Customers	#	1,887,679	299,553						1,588,126					
Total O&M Expense *	$	139,840,330	30,013,523						109,826,806					
(* w/o Allocation)														
Total Composite Factor														
Gross Direct PP&E	%	100.00%	14.78%	0.00%	0.00%	0.00%	0.00%	0.00%	85.22%					
Average Number of Customers	%	100.00%	15.87%	0.00%	0.00%	0.00%	0.00%	0.00%	84.13%					
Total O&M Expense	%	100.00%	21.46%	0.00%	0.00%	0.00%	0.00%	0.00%	78.54%					
Total Composite Factor for FY 2015	%	100.00%	17.37%	0.00%	0.00%	0.00%	0.00%	0.00%	82.63%					

Utilities + TLIG (No APT)

		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	303
			GSWTT	GSCKT	GSLAT	GSLAT	GSMIT	GSMST	GSMTT	GSTLT
Gross Direct PP&E	$	6,699,671,057	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	3,393,212,543	24,532,139
Average Number of Customers	#	3,060,530	299,553	243,084	74,693	272,260	332,626	250,173	1,588,126	15
Total O&M Expense *	$	268,722,855	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	109,826,806	1,132,882
(* w/o Allocation)										
Total Composite Factor										
Gross Direct PP&E	%	100.00%	10.45%	6.13%	2.94%	7.94%	14.13%	7.39%	50.65%	0.37%
Average Number of Customers	%	100.00%	9.79%	7.94%	2.44%	8.90%	10.87%	8.17%	51.89%	0.00%
Total O&M Expense	%	100.00%	11.17%	9.29%	3.26%	8.41%	14.14%	12.44%	40.87%	0.42%
Total Composite Factor for FY 2015	%	100.00%	10.47%	7.79%	2.88%	8.42%	13.05%	9.33%	47.80%	0.26%

COLORADO, LOUISIANA & MISSISSIPPI

A. Composite Allocation Factor

		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div
				GSCKW	GSLAW	GSLAW		GSMSW
Gross Direct PP&E	$	1,746,391,020		522,666,022	196,802,776	532,048,476		494,873,746
Average Number of Customers	#	840,210		243,084	74,693	272,260		250,173
Total O&M Expense *	$	89,745,438		24,974,685	8,753,909	22,587,103		33,429,741
(* w/o Allocation)								
Total Composite Factor								
Gross Direct PP&E	%	100.00%	0.00%	29.92%	11.27%	30.47%	0.00%	28.34%
Average Number of Customers	%	100.00%	0.00%	28.93%	8.89%	32.40%	0.00%	29.78%
Total O&M Expense	%	100.00%	0.00%	27.83%	9.75%	25.17%	0.00%	37.25%
Total Composite Factor for FY 2015	%	100.00%	0.00%	28.89%	9.97%	29.35%	0.00%	31.79%

Atmos 6 + TLIG (No APT or MidTex)

		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	303
			GSWTU	GSCKU	GSLAU	GSLAU	GSMIU	GSMSU	GSTLU
Gross Direct PP&E	$	3,306,458,514	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746	24,532,139
Average Number of Customers	#	1,472,404	299,553	243,084	74,693	272,260	332,626	250,173	15
Total O&M Expense *	$	158,896,049	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741	1,132,882
(* w/o Allocation)									
Total Composite Factor									
Gross Direct PP&E	%	100.00%	17.80%	15.81%	5.95%	16.09%	28.64%	14.97%	0.74%
Average Number of Customers	%	100.00%	20.35%	16.51%	5.07%	18.49%	22.59%	16.99%	0.00%
Total O&M Expense	%	100.00%	18.88%	15.72%	5.51%	14.22%	23.92%	21.04%	0.71%
Total Composite Factor for FY 2015	%	100.00%	19.01%	16.01%	5.51%	16.27%	25.05%	17.67%	0.48%

APT + 303 (TLGP)

		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	180	303
											CUGPT
Gross Direct PP&E	$	1,781,632,780	-	-	-	-	-	-	-	1,757,100,641	24,532,139
Average Number of Customers	#	362	-	-	-	-	-	-	-	347	15
Total O&M Expense *	$	82,709,534	-	-	-	-	-	-	-	81,576,653	1,132,882
(* w/o Allocation)											

ATMOS ENERGY CORPORATION

Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/14

			30	60	20	20	50	70	80	180	212	232	233	303	234 has the highest remaining Remainder
Gross Direct PP&E	%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	98.62%				1.38%	
Average Number of Customers	%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	95.85%				4.15%	
Total O&M Expense	%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	98.63%				1.37%	
Total Composite Factor for FY 2015	%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	97.70%				2.30%	
Atmos 6 + TLIG (No APT or MidTex)															
Gross Direct PP&E	$	3,306,458,514	588,658,574	522,666,022	196,802,776	532,048,476	946,876,781	494,873,746						24,532,139	
Average Number of Customers	#	1,472,404	299,553	243,084	74,693	272,260	332,626	250,173						15	
Total O&M Expense *	$	158,896,049	30,013,523	24,974,685	8,753,909	22,587,103	38,004,205	33,429,741						1,132,882	
(* w/o Allocation)															
Gross Direct PP&E	%	100.00%	17.80%	15.81%	5.95%	16.09%	28.64%	14.97%						0.74%	
Average Number of Customers	%	100.00%	20.35%	16.51%	5.07%	18.49%	22.59%	16.99%						0.00%	
Total O&M Expense	%	100.00%	18.88%	15.72%	5.51%	14.22%	23.92%	21.04%						0.71%	
Total Composite Factor for FY 2015	%	100.00%	19.01%	16.01%	5.51%	16.27%	25.05%	17.67%						0.48%	

Atmos Energy Corporation
Atmos Energy Mid States Div
Development of Allocation Factors
For Fiscal Year 2015

Div #	Division Name	Sept ' 14 Direct Property Plant & Equipment	Percent of MidStates Property	YE Sept '14 Total O &M w/o 922	Percent of MidStates O & M	YE Sept '14 Avg Number of Customers	Percent of MidStates Customers	Sub account	**MidStates Allocation Percent**	Sub account
		(1)	(2)	(3)	(4)	(5)	(6)		**(7)**	
									corrected way	
09	KENTUCKY	424,189,446	45.04%	14,546,900	49.63%	174,958	52.60%	91C09	**49.09%**	91O09
93	TENNESSEE	439,670,059	46.68%	10,204,309	34.82%	134,946	40.57%	91C93	**40.69%**	91O93
96	VIRGINIA	77,963,001	8.28%	4,557,634	15.55%	22,722	6.83%	91C96	**10.22%**	91O96
	Total	941,822,505.68	100.00%	29,308,843.07	100.00%	332,626	100.00%		100.00%	
	total 050	946,398,520.58		38,760,023.17		332,626.00				
	difference	4,576,014.90		9,451,180.10		-				
	091DIV	5,054,275.74		8,695,362.19						
	subtotal	(478,260.84)		755,817.91						
	095DIV	66,181.17		755,817.91						
	difference	(544,442.01)		0.00						

EXHIBIT ____ (LK-17)

Atmos Energy Corporation - Kentucky/Mid States Division
Adjust Composite Allocation Factor Percentages
By Removing Average Number of Customers and Changing Total O&M Expense to Total Operating Expense
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017

See AG WP File - ATT17 - FY15 Composite Factors for Rates_11.5.14 Analysis
See also spreadsheet reponses to AG 1-04 Att 5 and AG 2-11 Att 1 - Summed

As-Filed Composite Allocation Factors	12 Months Ended 9/30/2014	KY/MidStates Allocation %	Composite Allocation %
Allocation to KY/Mid States Division			
Gross Direct PPE - KY/MidStates Div	946,876,781		
Gross Direct PPE - Total	8,527,002,426		
Gross Direct PPE - KY/MidStates Div %		11.10%	
Average Number of Customers - KY/MidStates Div	332,626		
Average Number of Customers - Total	3,061,941		
Average Number of Customers - KY/Midstates Div %		10.86%	
Total O&M Expenses - KY/MidStates Div	38,004,205		
Total O&M Expenses - Total	373,655,056		
Total O&M Expenses - KY/MidStates Div %		10.17%	
Simple Average of Three Factors - KY/Mid States Div %			10.71%

Allocation of KY/Mid States Division to KY	12 Months Ended 9/30/2014	KY/MidStates Allocation %	Composite Allocation %
Gross Direct PPE - KY	424,189,446		
Gross Direct PPE - Total KY/TN/VA	941,822,506		
Gross Direct PPE - KY Div %		45.04%	
Average Number of Customers - KY	174,958		
Average Number of Customers - KY/TN/VA	332,626		
Average Number of Customers - KY Div %		52.60%	
Total O&M Expenses - KY	14,546,900		
Total O&M Expenses - KY/TN/VA	29,308,843		
Total O&M Expenses - KY Div %		49.63%	
Simple Average of Three Factors - KY/Mid States Div %			49.09%
As-Filed Shared Services Percentages Allocated to KY			5.26%

Atmos Energy Corporation - Kentucky/Mid States Division
Adjust Composite Allocation Factor Percentages
By Removing Average Number of Customers and Changing Total O&M Expense to Total Operating Expense
KPSC Case No. 2015-00343
Forecasted Test Period: Twelve Months Ended May 31, 2017

See AG WP File - ATT17 - FY15 Composite Factors for Rates_11.5.14 Analysis
See also spreadsheet reponses to AG 1-04 Att 5 and AG 2-11 Att 1 - Summed

AG Recommended Composite Allocation Factors	12 Months Ended 9/30/2014	KY/MidStates Allocation %	Composite Allocation %
Allocation to KY/Mid States Division			
Gross Direct PPE - KY/MidStates Div	946,876,781		
Gross Direct PPE - Total	8,527,002,426		
Gross Direct PPE - KY/MidStates Div %		11.10%	
Total Direct Operating Expenses - KY/MidStates Div	77,534,437		
Total Direct Operating Expenses - Total	833,415,635		
Total O&M Expenses - KY/MidStates Div %		9.30%	
Simple Average of Three Factors - KY/Mid States Div %			10.20%

Allocation of KY/Mid States Division to KY	12 Months Ended 9/30/2014	KY/MidStates Allocation %	Composite Allocation %
Gross Direct PPE - KY	424,189,446		
Gross Direct PPE - Total KY/TN/VA	941,822,506		
Gross Direct PPE - KY Div %		45.04%	
Total O&M Expenses - KY	34,650,487		
Total O&M Expenses - KY/TN/VA	68,876,650		
Total O&M Expenses - KY Div %		50.31%	
Simple Average of Three Factors - KY/Mid States Div %			47.67%
As-Filed Shared Services Percentages Allocated to KY			4.86%

Note: As Filed O&M excludes amounts for Georgia. Likewise, AG recommendation excludes amounts for Georgia.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Lane Kollen

Sworn to and subscribed before me on this 15th day of April 2016.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
15th day of April 2016.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**DOCKET NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 2016

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**DOCKET NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

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BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS**	**))))**	**DOCKET NO. 2015-00343**

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for regulated electric operations for Atmos Energy ("Atmos" or "Company"). I will also address certain capital structure issues as well as the cost of short-term debt. Finally, I will respond to the Direct Testimony of Dr. James Vander Weide, witness for the Company.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows.

First, I recommend that the Kentucky Public Service Commission ("KPSC" or "Commission") adopt a fair rate of return on equity of 9.0% for Atmos Energy. My recommended return on equity ("ROE") is based on a Discounted Cash Flow analysis using two comparison groups of regulated utilities, one consisting of gas distribution companies and the other based on regulated water companies. These are the same two groups of companies used by Dr. Vander Weide in his Direct Testimony on behalf of Atmos, adjusted for recent merger-related activity. My recommended 9.0% ROE is fully supported by current stock market data and expected growth rates and is consistent with the low interest rate environment that is present today.

Second, I recommend that the commitment and banking fees expenses that Atmos included in its cost of short-term debt be removed and placed into operations and maintenance expenses. I also recommend that the Commission adopt the Company's proposed cost of short-term debt, excluding the commitment and banking fees.

Third, I recommend that the Commission reject Atmos' proposed 55.32% equity ratio for the test year. This equity ratio is inflated and inconsistent with the Company's historical equity ratios. Instead, I recommend that the Commission authorize a 52.99% equity ratio consistent with the Company's base period capital structure. The difference between Atmos' requested equity ratio and my recommended 52.99% equity ratio should be made up by increasing the Company's short-term debt. Given the current low interest rate environment, Atmos should employ additional short-term debt to fund its capital expenditures and lower its cost of capital. In connection with this recommendation, if the Commission adopts Atmos' requested common equity ratio of 55.32%, then I recommend that the allowed ROE should be reduced to 8.60%.

Fourth, my recommended adjusted weighted cost of capital for Atmos is 7.05%.

Fifth, I recommend that the Commission reject Dr. Vander Weide's recommended 10.5% cost of equity. For reasons that I shall explain in Section IV of my testimony, a cost of equity of 10.5% is overstated, inconsistent with current market required returns, and would result in an excessive revenue requirement for Atmos.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. Exhibit ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through March 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of March 2016 the average public utility bond yield was 4.40%, representing a decline of 168 basis points, or 1.68% from January 2008. Likewise, the 20-year Treasury bond declined to 2.28% in March 2016, a decline of 2.07% (207 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit ___(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

[1] http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. On June 19, 2013, the Federal Open Market Committee (“FOMC”) issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its

[2] http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm

> dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Since the Federal Reserve's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The closing yield for March 2016 was 2.28%, a decline of 124 basis points since January 2014.

[3] http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm

Q. Has the Federal Reserve recently indicated any important changes to its monetary policy?

A. Yes. Recently the Federal Reserve raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release on March 16, 2016 stating that it would continue to maintain this target range at present.[4] This press release also stated:

> "The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation."

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my

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[4] http://www.federalreserve.gov/newsevents/press/monetary/20160316a.htm

testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[5]

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, all the market evidence I examined suggests that investors require lower rates of return on equity on regulated utility stocks. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

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5 Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

Q. How does the investment community regard the regulated gas distribution industry as a whole?

A. The Value Line Investment Survey's March 4, 2016 summary report on the Natural Gas Utility industry noted the following:

> Stocks in Value Line's Natural Gas Utility Industry have performed nicely thus far in 2016. (Some were even trading at record-high price levels at the time of this writing.) We believe one factor is expectations of generally decent earnings in 2016. Too, during this period of greater financial market uncertainty (caused by concerns over such matters as persistently low oil prices and China's decelerating economy) the equities in our category appear more enticing than those of other sectors. That's largely because they offer well-covered, generous amounts of dividend income, which provide a measure of much-needed stability. What's more, there are some selections here that are favorably ranked for Timeliness, not a common occurrence since their historical price movements have tended to be steady.

Q. What do you conclude from the aforementioned quote from Value Line?

A. Utilities in general and gas utilities in particular continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve's future moves on interest rates, utilities' prices have made solid gains since the beginning of 2016. For example, the Dow Jones utility average opened January 2016 at 574.51 and closed at 660.11 on April 8, 2016. This represents a gain of 14.9% since the beginning of this year.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy in 2016 and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to slowly recover from the recession that began in 2007.

Q. What are the current credit ratings and bond ratings for Atmos Energy?

A. Atmos Energy's current unsecured bond rating from Standard and Poor's is A- and A2 from Moody's. These ratings are both solidly investment grade ratings. Atmos also carries a positive ratings outlook from Standard and Poor's, indicating that the Company's rating could be raised "as a result of consistent and timely recovery of invested capital."[6]

6 https://www.standardandpoors.com/en_US/web/guest/article/-/view/type/HTML/id/1472798

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Atmos.

A. I employed a Discounted Cash Flow ("DCF") analysis using two groups of regulated utilities. One group is comprised of gas distribution companies and the other of water utilities. With two adjustments to the gas distribution group, these are the same groups used by Dr. Vander Weide in his Direct Testimony. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Atmos.

My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 9.0% ROE for Atmos, the results from the CAPM tend to support this recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Atmos?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Atmos. In estimating the cost of equity for a gas distribution company such as Atmos, I would begin with the group of gas distribution utilities followed by the Value Line Investment Survey. This is the same basic approach that Dr. Vander Weide followed in his Direct Testimony. He also added a group of water utilities as a supplement to the gas distribution group. This general approach is quite reasonable for estimating the cost of equity for Atmos in this case and I shall adopt it for purposes of my analysis as well.

Q. Did you make any adjustments to the two groups used by Dr. Vander Weide?

A. Yes. Dr. Vander Weide excluded companies from his group that were involved in merger activity, a selection criterion that I also use. In October 2015, Piedmont Natural Gas agreed to be acquired by Duke Energy. Therefore, it is now appropriate to exclude Piedmont Natural Gas from the gas distribution group for purposes of estimating the cost of equity. In addition, I added Southwest Gas to the gas distribution group. This company has growth rate forecasts from Value Line and IBES and is not subject to merger activity. Therefore, Southwest Gas should be included in the gas distribution group.

Q. What was your first step in determining the DCF return on equity for the comparison groups of regulated utilities?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from October 2015 through March 2016. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the gas distribution group is 3.11%. These calculations are shown in Exhibit ___(RAB-3).

The average dividend yield for the water utility group is 2.54%, the calculation for which may be found in Exhibit ____(RAB-5).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the comparison groups?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of Exhibit ____(RAB-4) shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from IBES and Zacks for the companies in the gas distribution group. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only sources of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

Exhibit ____(RAB-6) presents the dividend and earnings growth forecasts for the water utility group.

Q. How did you proceed to determine the DCF return of equity for the two comparison groups?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit ___(RAB-4) presents my standard method of calculating dividend yields, growth rates, and return on equity for the gas distribution group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 3.11% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the comparison group under consideration.

Exhibit ____(RAB-6) presents the same information for the water utility group. Please note that Zack's did not have earnings growth forecasts for Middlesex Water Company, SJW Corp., and York Water Company so I simply substituted the IBES growth rates for those companies.

Q. What are the results of your constant growth DCF model?

A. Referring to the gas distribution group in Exhibit ____(RAB-4), for the average growth rates the results range from 7.56% to 9.16%, with the average of these results being 8.61%. Using the median growth rates, the results range from 6.92% to 9.46%, with the average of these results being 8.56%.

Referring to the water utility group in Exhibit____(RAB-6), DCF results using the average growth rates range from 7.91% to 9.25%, with the average of these results being 8.65%. Using the median growth rates, the results range from 7.60% to 9.12%, with the average of these results being 8.24%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[7] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total

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[7] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for April 4, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit ____(RAB-7). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.93% to 12.0%. The average of these three market returns is 10.97%.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit ____(RAB-8) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit ___(RAB-8) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.01% - 7.01%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[8] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the historical risk premium because "it is not believed that P/E will continue to increase

[8] *2014 Ibbotson SBBI Classic Yearbook*, Morningstar, pp. 156 - 158.

in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in Exhibit ___(RAB-8).

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from October 2015 through March 2016. The 20-year Treasury bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the gas distribution group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.79.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 9.01% - 9.21%. Using historical risk premiums, the CAPM results are 6.44% - 8.03%.

<u>ROE Conclusions and Recommendations</u>

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 1 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 1

ATMOS ENERGY
ROE RESULTS SUMMARY

DCF Results:	
Average Growth Rates, Gas Group	
- High	9.16%
- Low	7.56%
- Average	8.61%
Median Growth Rates, Gas Group	
- High	9.46%
- Low	6.92%
- Average	8.56%
Average Growth Rates, Water Group	
- High	9.25%
- Low	7.91%
- Average	8.65%
Median Growth Rates, Water Group	
- High	9.12%
- Low	7.60%
- Average	8.24%
CAPM:	
- 5-Year Treasury Bond	9.01%
- 20-Year Treasury Bond	9.21%
- Historical Returns	6.44% - 8.03%

Q. What is your recommended return on equity for Atmos?

A. I recommend that the Commission adopt a 9.0% return on equity for Atmos. My recommendation is consistent with the midpoint of the range of DCF results that employed earnings growth forecasts for the gas distribution group. Based on current market evidence, a 9.0% return on equity is fair and reasonable for A/A-rated gas utility company like Atmos.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. All of the market evidence I examined fully supports my ROE recommendation for Atmos in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for Atmos, as well as other regulated gas and water utilities, reflects this low interest rate environment. A 9.0% ROE recommendation for Atmos is by no means too low in the current economic and financial environment.

In fact, the average DCF results for both the gas and water groups suggest that an allowed ROE in the range of 8.40% - 8.70% would be reasonable for the Company. However, I am adjusting my recommended ROE upward due to the change in Federal Reserve policy I described in Section II of my testimony. The Federal Reserve recently increased its target range for the federal funds rate and I believe it is likely that the Fed could raise interest rates slightly later this year. Given this change in policy, an upward adjustment to my ROE recommendation appears reasonable at this particular point in time.

Cost of Short-Term Debt

Q. Please explain how you adjusted the Company's cost of short-term debt.

A. According to Schedule J-2 Atmos included commitment fees of $2.273 million in its requested cost of short-term debt. These fixed fees should not be included in the cost of short-term debt. Including these largely fixed fees in short-term debt costs requires the Commission to recalculate the percentage cost of short-term debt whenever it changes the rate base or modifies the amount of short-term debt.

Instead, I recommend that these fees be collected in O&M expenses. In this manner, the Commission ensures that the Company fully recovers these fixed expenses. At the same time, only the short-term debt interest rate itself is reflected in the weighted cost of capital regardless of the adjustments to rate base or the modifications to the capital structure.

Excluding commitment fees, Atmos' cost of short-term debt is 0.396%. This is the cost rate I recommend the Commission adopt for the Company's cost of capital in this case.

Capital Structure and Weighted Cost of Capital

Q. What is your recommended weighted cost of capital?

A. My weighted cost of capital recommendation is 7.05%. It is based on an adjusted equity ratio of 52.99%, an adjusted short-term debt ratio of 8.80%, an adjusted short-term debt cost of 0.40%, and my recommended ROE of 9.0%.

TABLE 2

ATMOS ENERGY
WEIGHTED COST OF CAPITAL

	Percentage	Cost	Wtd. Cost
Short-term Debt	8.80%	0.40%	0.03%
Long-term Debt	38.21%	5.90%	2.25%
Common Equity	52.99%	9.00%	4.77%
Total	100.00%		7.05%

Q. Please explain why you adjusted the Company's common equity ratio.

A. The Company's requested common equity ratio of 55.32% in the forecasted period is unreasonable and should be rejected by the Commission.

Atmos' Schedule J-1 shows that the percentage of common equity in the base period capital structure is 52.99%. In the forecasted period, Schedule J-1 shows an increase in common equity of $318.1 million, which is nearly equal to the increase in total capital from the base period to the forecasted period. Atmos has thus assumed, without foundation or analysis, that it is reasonable to finance nearly the entire amount of increased capital in the forecasted period with common equity. It is this assumption that caused the common equity ratio to rise from 52.99% to 55.32%.

Common equity is the most expensive form of financing available to the Company. In today's low interest rate environment Atmos should be taking full advantage of additional debt financing in order to lower its total cost of capital to ratepayers.

Q. Is the Company's forecasted common equity ratio consistent with its common equity ratios over the last ten years?

A. It certainly is not. Table 3 below shows Atmos' common equity ratios including short-term debt from 2006 through the base period. The percentages are based on using the daily average of short-term debt over the year. This information came from the Company's response to Staff 1-03.

TABLE 3

Atmos Historical Common Equity Ratios

2006	44.10%
2007	48.10%
2008	47.70%
2009	50.20%
2010	50.40%
2011	49.10%
2012	51.30%
2013	48.80%
2014	53.30%
Base Year	52.99%
Forecast Yr.	***55.32%***

Table 3 clearly shows how excessive the Company's requested common equity ratio is compared to the last 10 years. With the exception of 2014, even the base year common equity ratio is greater than the historical ratios.

Q. How do you recommend that the Commission adjust the Company's capital structure to maintain the base period common equity ratio of 52.99%?

A. I recommend that the Commission set the Company's common equity ratio in the forecasted year to 52.99%, which results in a total common equity amount of $3.405 billion. I also recommend that the amount of short-term debt be increased to $0.565 billion, or 8.80%. The Company's requested amount of long-term debt should be accepted.

Q. How does the Company's capital structure compare with the capital structure of your comparison group?

A. Table 4 below presents the 2015 common equity ratios for the companies in the gas utility group. These numbers were taken from the most recent Value Line Investment Survey reports for each company.

TABLE 4

GAS UTILITY GROUP
2015 COMMON EQUITY RATIOS

Atmos Energy	56.5%
LaClede Group	47.0%
New Jersey Resources	56.8%
Northwest Natural Gas	57.6%
South Jersey Industries	51.5%
Southwest Gas	50.7%
UGI Corp.	44.0%
WGL Holdings	56.1%
Average	52.5%

Source: Value Line Investment Survey

The base period common equity ratio of 52.99% for Atmos is consistent with the average common equity ratio for the gas utility group.

Q. If the Commission accepts the Company's requested 55.32% common equity ratio, should it also reduce your recommended ROE of 9.0%?

A. Yes. If the Commission accepts the Company's requested common equity ratio for the forecasted period, then my recommended ROE should be reduced in order to compensate for the lower financial risk that would result. I recommend that the Commission adopt a ROE in the range of 8.56% to 8.61%, which is the range of my

DCF results for the gas utility group. A ROE of 8.60% would be reasonable given the higher common equity ratio of 55.32%.

IV. RESPONSE TO ATMOS ENERGY TESTIMONY

Q. Have you reviewed the Direct Testimony of Dr. Vander Weide?

A. Yes.

Q. Please summarize your conclusions with respect to their testimony and return on equity recommendation.

A. My conclusions regarding Dr. Vander Weide's testimony and return on equity recommendations are as follows.

First, Dr. Vander Weide's recommended ROE of 10.5% is overstated and does not reflect the return requirement of investors in today' marketplace. A DCF model that is properly specified and applied shows a much lower range of results.

Second, Dr. Vander Weide's DCF results are overstated. This overstatement is due to the use of stale stock prices, the use of quarterly compounding in the calculation of the dividend yield component of the DCF model, and the addition of flotation costs.

Third, Dr. Vander Weide’s risk premium results are overstated and should be rejected. In particular, Dr. Vander Weide's use of a forecasted A-rated utility bond yield greatly inflated his risk premium results. For reasons I will explain later, the use of forecasted bond yields in the risk premium and CAPM estimates of ROE should be rejected.

Fourth, Dr. Vander Weide included a size adjustment that inflated his CAPM results. He also testified that the CAPM results are likely understated for companies such as regulated utilities that have betas less than 1.0. I disagree with this conclusion.

Q. Please summarize Dr. Vander Weide's approach to the DCF model and its results.

A. Dr. Vander Weide employed two comparison groups of companies to estimate the cost of equity for Atmos. One group consisted of publicly traded gas utilities and the other was comprised of water companies. Dr. Vander Weide confined his growth rate analysis to earnings forecasts from IBES for the gas utility group. For the water utility group he used an average of IBES and Value Line earnings growth forecasts. He also utilized quarterly compounding in his DCF calculations. Dr. Vander Weide did not consider forecasted dividend growth for either group of companies.

Q. What period did Dr. Vander Weide use to obtain stock prices for his DCF model?

A. Dr. Vander Weide used the 3-month period from June through August 2015.

Q. Are these prices out of date?

A. Yes. Since Dr. Vander Weide filed his testimony stock prices for the companies in the gas and water utility groups have increased. As stock prices increase, dividend yields will fall give a constant level of dividends. Using Dr. Vander Weide's work papers, I calculate that the current dividend yield for his gas group using his 3-month period for stock prices is 3.40%. The dividend yield using my 6-month period for stock prices, October 2015 through March 2016, is 3.16% for this group, which excludes Southwest Gas. Thus, current dividend yields are on average 24 basis points lower now than they were when Dr. Vander Weide filed his testimony.

Q. Should Dr. Vander Weide have included dividend growth forecasts in his DCF analyses?

A. Yes. Dr. Vander Weide erred in failing to include available dividend growth forecasts from Value Line in his DCF analyses. With respect to regulated utility companies, dividend growth provides the primary source of cash flow to the investor. It is certainly the case that earnings growth fuels dividend growth and should be considered in estimating the ROE using the DCF model; however, Value Line's dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. I agree that earnings growth is the primary factor considered by investors, but it should not be considered the only factor, particularly if near-term dividend growth is expected to be less than longer-term earnings growth.

Exhibit ____(RAB-4) shows that Value Line's forecasted dividend growth for the gas distribution company group is lower than the earnings growth forecasts. Using dividend growth would have lowered Dr. Vander Weide's DCF results for the gas group. I also note that Exhibit ____(RAB-6) shows that dividend growth forecasts for the water utility group are on average higher than the earnings growth forecasts.

Q. On page 18, Dr. Vander Weide rejects the annual DCF model and recommends that the Commission accept a quarterly DCF calculation. Is a quarterly version of the DCF model appropriate for determining the allowed ROE for regulated utility companies?

A. No. The quarterly DCF model proposed by Dr. Vander Weide is unnecessary, overcompensates investors, and results in excessive costs for ratepayers.

I agree that dividends are paid quarterly and that investors have the ability to reinvest those dividends. This means that through quarterly compounding, if a utility company is allowed a 10% return on equity then investors will realize slightly more than a 10% return due to the reinvestment effect. However, this effect does not need to be added to the annual model that uses the 1 + 0.5 times growth adjustment that I used in my DCF calculations. Including quarterly compounding in the DCF calculation would basically compensate investors twice for the reinvestment effect.

Further, quarterly compounding is likely already accounted for in a company's stock price since investors know that dividends are paid quarterly and that they may reinvest those cash flows. Adding an incremental return for quarterly compounding merely serves to inappropriately and unnecessarily enhance the expected return on equity.

Q. Beginning on page 23 of his Direct Testimony, Dr. Vander Weide discussed his inclusion of a flotation cost adjustment in his DCF analyses. Do you agree with a flotation cost adjustment?

A. No, I do not. I recommend that the Commission reject a flotation cost adjustment in setting the cost of equity for Atmos.

In my opinion it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A

DCF model using current stock prices should already account for investor expectations, if any, regarding the collection of flotation costs. Multiplying the dividend yield by a 3% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Q. What is the overstatement of Dr. Vander Weide's DCF results due to the inclusion of quarterly compounding and flotation costs?

A. I calculated that quarterly compounding added 30 basis points to Dr. Vander Weide's DCF results. Flotation costs added another 20 basis points to his DCF results for a total of 50 basis points, or 0.50%.

<u>**Risk Premium Model**</u>

Q. Please present your conclusions regarding the results of Dr. Vander Weide’s ex-ante risk premium analyses.

A. Dr. Vander Weide’s ex-ante risk premium results are overstated and cannot be relied upon for setting Atmos' allowed ROE in this case. His results are overstated due to:

1. Use of a “forecasted” A-rated bond yield.
2. Sole use of forecasted earnings growth to calculate the DCF return for the gas group.
3. Inclusion of flotation costs.
4. Use of quarterly compounding in his DCF calculation.

I have already discussed items 2 through 4 previously in my testimony and they apply to the manner in which Dr. Vander Weide calculated the DCF return for his comparable group of gas distribution utilities. Dr. Vander Weide did not consider lower dividend growth in calculating the DCF return for his comparable gas company group. This omission likely overstates the expected DCF return for the group. And the inclusion of flotation costs and quarterly compounding further inflates his group DCF results. Taken together, all three of these problems overstate the risk premium he used in his analysis.

Q. How does the use of a forecasted A-rated bond yield overstate the risk premium return on equity?

A. Dr. Vander Weide's use of a forecasted A-rated utility bond yield should be rejected.

Current, observable bond yields should be used for any risk premium analysis. Current bond yields reflect all relevant current market information, including expectations about future interest rates. If investors really expected A-rated utility bonds to be significantly higher than they are now, they likely would have already adjusted the current bond yield to avoid or minimize capital losses in the future.

Q. How does the forecasted A-rated utility bond yield used by Dr. Vander Weide compare to current A-rated utility bond yields?

A. The March 2016 yield on A-rated utility bonds from the Mergent Bond Record was 4.16%. Dr. Vander Weide's forecasted A-rated utility bond yield is 6.20%, *which is over 200 basis points higher than the current yield*. On its face, Dr. Vander Weide's forecasted bond yield is so far removed from current interest rates that the Commission should simply reject his risk premium analysis and results out of hand.

Q. On page 32, lines 18 through 21, Dr. Vander Weide opined that current interest rates are a poor indicator of future interest rates due to the Federal Reserve's "extraordinary" efforts to keep interest rates low. Please comment on this testimony.

A. Current interest rates are indeed the best indicators of investor sentiment regarding the future course of interest rates. Current rates embody expectations regarding the Federal Reserve's possible future moves on interest rates, which are by no means certain. In my opinion, it is likely that interest rates will rise in the future but no one really knows by how much or when such future movements will occur. Until then, current interest rates should be used in the risk premium and CAPM estimates of the investor required return on equity.

Q. What are your conclusions with respect to Dr. Vander Weide's ex-post risk premium approach?

A. First, it is risky to assume that investors require an unchanging risk premium based on long-term historical returns of stocks over bonds. Changing economic conditions will likely affect investors' risk premium requirement. What investors require today may be quite different from a long-term historical risk premium.

Second, Dr. Vander Weide calculated an historical risk premium using the S&P 500 stock portfolio. Investor expected risk premiums for gas distribution utility stocks over bonds are likely much lower than the expected risk premium for unregulated companies in the S&P 500. Using the S&P 500 risk premium overstated the risk premium ROE for a lower-risk gas company such as Atmos.

Third, Dr. Vander Weide's ex-post risk premium results are significantly overstated due to his inappropriate use of a forecasted A-rated bond. *Using the March 2016 A-rated utility bond yield of 4.16% and adding this to his risk premium range of 3.9% - 4.5% results in an ex-post risk premium return on equity range of 8.06% - 8.66%.*

<u>CAPM Analysis</u>

Q. On page 42 of his Direct Testimony, Dr. Vander Weide cited a number of studies in support of his proposition that the CAPM underestimates required returns for securities with betas less than 1.0. On page 44, he concludes that the financial literature supports the proposition that the CAPM understates the cost of equity for companies such as public utilities with betas less than 1.0. Please address Dr. Vander Weide's testimony in this area.

A. Although Dr. Vander Weide cited a number of studies on page 42, the problem is that there is no evidence that the CAPM bias he alleges has any applicability to regulated utility companies. Regulated gas utilities have betas lower than 1.0 because they are lower in risk than the market as a whole. Thus, the average gas utility group beta from my group, 0.79, reflects the lower risk of regulated gas distribution operations vis-à-vis the unregulated market. Dr. Vander Weide failed to show any downward CAPM bias related to gas utility betas.

Q. On page 40 of his Direct Testimony, Dr. Vander Weide suggested the addition of a size premium to his CAPM results to account for the small market capitalization of natural gas distribution companies. Do you agree with the inclusion of a size premium?

A. No. It is true that the Ibbotson Yearbooks discuss size premiums, but they do not evaluate whether any such size premium is applicable to regulated utilities generally, or to regulated gas companies specifically. Thus, the size premiums shown on Table 1, page 40 of Dr. Vander Weide's Direct Testimony have no relevance whatsoever for lower-risk regulated gas distribution utilities such as Atmos.

Q. On page 46 of his Direct Testimony, Dr. Vander Weide stated that his recommended ROE of 10.5% was conservative because the market value capital structure of his proxy companies contains a higher equity percentage than Atmos' book value capital structure. Please comment on Dr. Vander Weide's testimony on this point.

A. I disagree with Dr. Vander Weide on this point. First, ratemaking does not use the market value equity ratio for Atmos or any of the other companies in the two groups that Dr. Vander Weide and I used to estimate the cost of equity. Utility regulators use book value equity ratios to calculate the regulated cost of capital. In this sense, Atmos is no different from the utilities in the gas and water company groups. In terms of assessing relative financial risk, one should instead look at the book equity ratios of Atmos and the companies in the two groups. I demonstrated earlier in my testimony that Atmos' base period equity percentage is consistent with the group of gas utilities I used to estimate the cost of equity. No additional adjustment for financial risk is required. Furthermore, a 10.5% ROE is excessive is the current economic environment, rather than conservative.

Q. Does this complete your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**DOCKET NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
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APRIL 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278- E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006- 0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008- 2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008- 2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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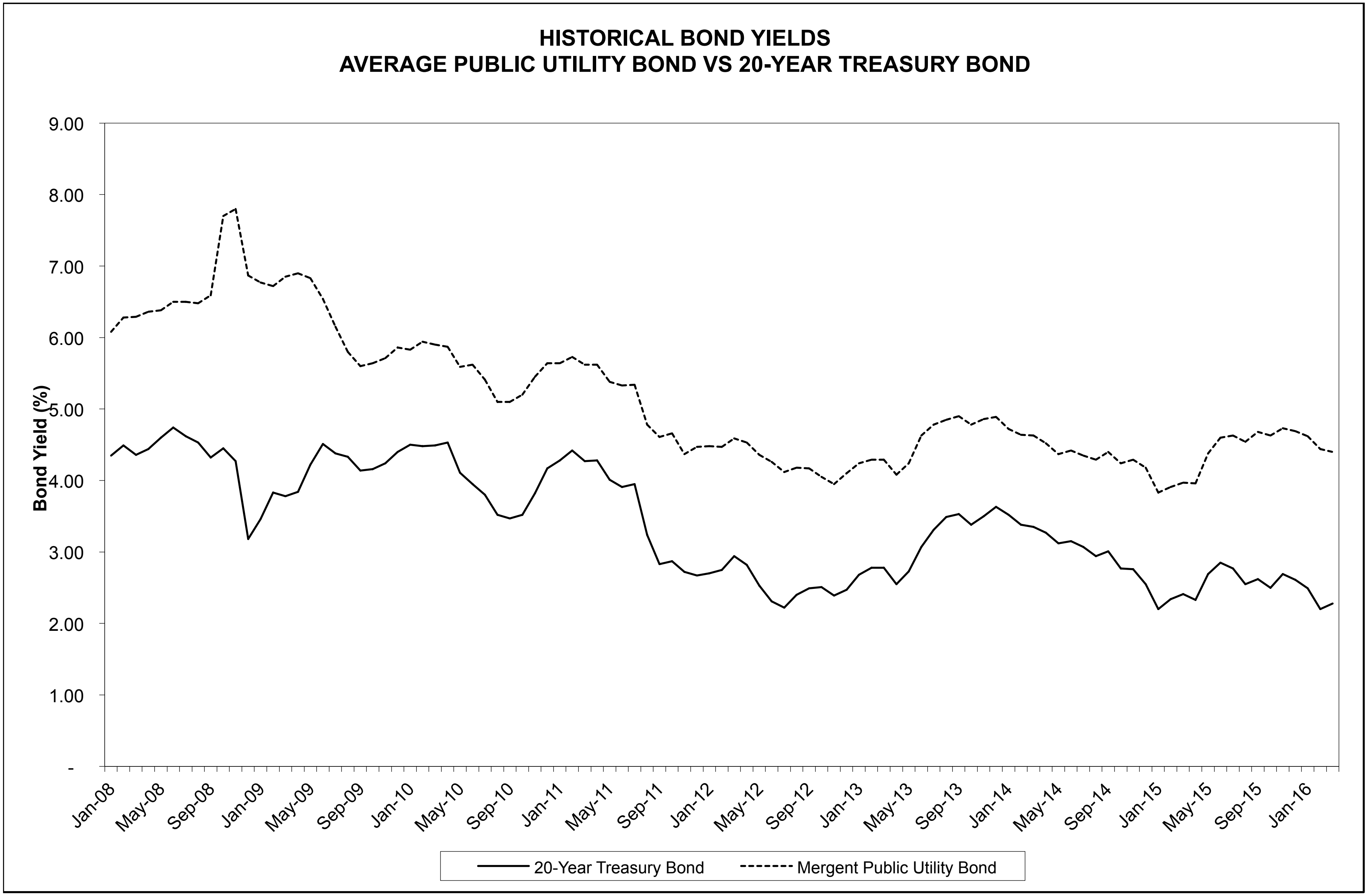
Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/116	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure

Exhibit ___(RAB-2)



ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
Atmos Energy	High Price ($)	74.600	71.900	69.220	64.790	63.770	63.460
	Low Price ($)	68.600	67.940	60.000	60.420	59.220	57.370
	Avg. Price ($)	71.600	69.920	64.610	62.605	61.495	60.415
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.390
	Mo. Avg. Div.	2.35%	2.40%	2.60%	2.68%	2.73%	2.58%
	6 mos. Avg.	2.56%					
LaClede Group	High Price ($)	68.790	66.430	63.940	61.040	59.100	59.380
	Low Price ($)	64.390	63.310	57.100	55.240	54.330	53.860
	Avg. Price ($)	66.590	64.870	60.520	58.140	56.715	56.620
	Dividend ($)	0.490	0.490	0.490	0.490	0.460	0.460
	Mo. Avg. Div.	2.94%	3.02%	3.24%	3.37%	3.24%	3.25%
	6 mos. Avg.	3.18%					
New Jersey Resources	High Price ($)	36.850	36.570	35.570	34.070	31.970	31.850
	Low Price ($)	33.320	33.370	32.320	28.020	29.420	29.670
	Avg. Price ($)	35.085	34.970	33.945	31.045	30.695	30.760
	Dividend ($)	0.240	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	2.74%	2.75%	2.83%	3.09%	3.13%	3.12%
	6 mos. Avg.	2.94%					
Northwest Natural Gas	High Price ($)	54.510	53.880	52.010	51.850	48.910	48.610
	Low Price ($)	48.900	49.410	49.300	47.780	45.380	45.030
	Avg. Price ($)	51.705	51.645	50.655	49.815	47.145	46.820
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.62%	3.62%	3.70%	3.76%	3.97%	4.00%
	6 mos. Avg.	3.78%					
South Jersey Industries	High Price ($)	29.140	26.940	24.860	24.400	27.020	27.340
	Low Price ($)	25.270	24.540	22.060	21.240	22.830	24.650
	Avg. Price ($)	27.205	25.740	23.460	22.820	24.925	25.995
	Dividend ($)	0.264	0.264	0.264	0.264	0.251	0.251
	Mo. Avg. Div.	3.88%	4.10%	4.50%	4.63%	4.03%	3.86%
	6 mos. Avg.	4.17%					
Southwest Gas	High Price ($)	67.290	62.430	58.920	56.710	62.330	62.890
	Low Price ($)	59.490	58.070	53.510	50.530	54.430	56.430
	Avg. Price ($)	63.390	60.250	56.215	53.620	58.380	59.660
	Dividend ($)	0.405	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.56%	2.69%	2.88%	3.02%	2.77%	2.72%
	6 mos. Avg.	2.77%					

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
UGI Corp.	High Price ($)	40.850	37.210	34.370	34.980	37.510	36.940
	Low Price ($)	36.890	33.330	31.590	31.510	33.680	34.160
	Avg. Price ($)	38.870	35.270	32.980	33.245	35.595	35.550
	Dividend ($)	0.228	0.228	0.228	0.228	0.228	0.228
	Mo. Avg. Div.	2.35%	2.59%	2.77%	2.74%	2.56%	2.57%
	6 mos. Avg.	2.59%					
WGL Holdings	High Price ($)	74.100	69.200	66.810	65.550	62.590	63.200
	Low Price ($)	67.230	62.930	59.990	58.620	57.040	56.900
	Avg. Price ($)	70.665	66.065	63.400	62.085	59.815	60.050
	Dividend ($)	0.463	0.463	0.463	0.463	0.463	0.463
	Mo. Avg. Div.	2.62%	2.80%	2.92%	2.98%	3.10%	3.08%
	6 mos. Avg.	2.92%					

Average Dividend Yield 3.11%

Source: Yahoo! Finance

Exhibit ____ (RAB-4)

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.00%	5.00%	6.60%	6.40%
LaClede Group	3.50%	9.00%	4.50%	4.80%	4.70%
New Jersey Resources	3.00%	1.50%	5.00%	6.50%	6.50%
Northwest Natural Gas	1.50%	5.00%	3.00%	4.00%	4.00%
South Jersey Industries	6.50%	5.50%	4.00%	6.00%	6.00%
Southwest Gas	7.50%	7.00%	6.50%	5.00%	4.00%
UGI Corp.	4.00%	4.50%	8.00%	6.70%	8.00%
WGL Holdings	2.50%	5.00%	4.50%	7.30%	8.00%
Average Growth Rates	4.38%	5.44%	5.06%	5.86%	5.95%
Median Growth Rates	3.75%	5.25%	4.75%	6.25%	6.20%

Sources: Zack's and Thomson Earnings Reports, retrieved April 4, 2016
Value Line Investment Survey, March 4, 2016

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Average Growth Rate	4.38%	5.44%	5.86%	5.95%	5.41%
Expected Div. Yield	3.18%	3.20%	3.20%	3.21%	3.20%
DCF Return on Equity	***7.56%***	***8.64%***	***9.06%***	***9.16%***	***8.61%***
Method 2:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Median Growth Rate	3.75%	5.25%	6.25%	6.20%	5.36%
Expected Div. Yield	3.17%	3.20%	3.21%	3.21%	3.20%
DCF Return on Equity	***6.92%***	***8.45%***	***9.46%***	***9.41%***	***8.56%***

ATMOS ENERGY
WATER UTILITY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
American States Water	High Price ($)	43.080	47.240	45.470	44.140	42.400	42.400
	Low Price ($)	38.250	41.830	39.160	39.690	39.670	40.310
	Avg. Price ($)	40.665	44.535	42.315	41.915	41.035	41.355
	Dividend ($)	0.224	0.224	0.224	0.224	0.224	0.224
	Mo. Avg. Div.	2.20%	2.01%	2.12%	2.14%	2.18%	2.17%
	6 mos. Avg.	2.14%					
American Water Works	High Price ($)	70.100	68.490	65.040	61.200	58.400	59.200
	Low Price ($)	64.930	63.160	58.900	56.400	55.130	54.620
	Avg. Price ($)	67.515	65.825	61.970	58.800	56.765	56.910
	Dividend ($)	0.340	0.340	0.340	0.340	0.340	0.340
	Mo. Avg. Div.	2.01%	2.07%	2.19%	2.31%	2.40%	2.39%
	6 mos. Avg.	2.23%					
Aqua America	High Price ($)	32.440	32.340	31.530	31.090	29.700	28.790
	Low Price ($)	30.450	30.560	28.350	28.830	28.050	26.200
	Avg. Price ($)	31.445	31.450	29.940	29.960	28.875	27.495
	Dividend ($)	0.178	0.178	0.178	0.178	0.178	0.178
	Mo. Avg. Div.	2.26%	2.26%	2.38%	2.38%	2.47%	2.59%
	6 mos. Avg.	2.39%					
California Water	High Price ($)	27.330	25.860	25.140	24.200	22.830	24.350
	Low Price ($)	24.720	23.200	22.480	22.090	21.010	21.640
	Avg. Price ($)	26.025	24.530	23.810	23.145	21.920	22.995
	Dividend ($)	0.173	0.173	0.168	0.168	0.168	0.168
	Mo. Avg. Div.	2.66%	2.82%	2.82%	2.90%	3.07%	2.92%
	6 mos. Avg.	2.87%					
Connecticut Water	High Price ($)	45.660	43.940	43.120	39.930	37.360	38.490
	Low Price ($)	41.240	40.360	37.480	34.770	34.150	35.970
	Avg. Price ($)	43.450	42.150	40.300	37.350	35.755	37.230
	Dividend ($)	0.268	0.268	0.268	0.268	0.268	0.268
	Mo. Avg. Div.	2.47%	2.54%	2.66%	2.87%	3.00%	2.88%
	6 mos. Avg.	2.74%					
Middlesex Water	High Price ($)	32.100	29.770	29.010	28.020	25.970	26.650
	Low Price ($)	26.460	27.300	25.000	24.250	24.010	23.400
	Avg. Price ($)	29.280	28.535	27.005	26.135	24.990	25.025
	Dividend ($)	0.199	0.199	0.199	0.199	0.199	0.199
	Mo. Avg. Div.	2.72%	2.79%	2.95%	3.05%	3.19%	3.18%
	6 mos. Avg.	2.98%					
SJW Corp.	High Price ($)	37.860	37.230	32.630	30.890	31.760	33.840
	Low Price ($)	34.850	31.390	28.580	27.600	28.030	30.460
	Avg. Price ($)	36.355	34.310	30.605	29.245	29.895	32.150
	Dividend ($)	0.203	0.203	0.195	0.195	0.195	0.195
	Mo. Avg. Div.	2.23%	2.37%	2.55%	2.67%	2.61%	2.43%
	6 mos. Avg.	2.48%					

ATMOS ENERGY
WATER UTILITY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
York Water Company	High Price ($)	30.990	28.770	26.670	26.670	24.000	23.860
	Low Price ($)	26.580	26.270	23.790	22.810	22.180	20.930
	Avg. Price ($)	28.785	27.520	25.230	24.740	23.090	22.395
	Dividend ($)	0.156	0.156	0.156	0.156	0.156	0.156
	Mo. Avg. Div.	2.17%	2.27%	2.47%	2.52%	2.70%	2.79%
	6 mos. Avg.	2.49%					
Average Dividend Yield		2.54%					

Source: Yahoo! Finance

ATMOS ENERGY
WATER UTILITY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
American States Water	7.00%	6.00%	6.00%	3.80%	3.85%
American Water Works	10.50%	8.00%	5.00%	7.40%	7.60%
Aqua America	9.00%	7.00%	4.50%	6.20%	5.85%
California Water Service Group	6.50%	6.00%	4.00%	5.00%	5.00%
Connecticut Water Services	4.50%	4.50%	4.50%	5.00%	5.00%
Middlesex Water Company	3.00%	3.50%	3.00%	2.70%	2.70%
SJW Corp.	6.00%	1.50%	4.00%	14.00%	14.00%
York Water Company	6.50%	6.00%	4.00%	4.90%	4.90%
Averages	6.63%	5.31%	4.38%	6.13%	6.11%
Median Values	6.50%	6.00%	4.25%	5.00%	5.00%

Sources: Zack's and Thomson Earnings Reports, retrieved April 4, 2016
Value Line Investment Survey, April 15, 2016

ATMOS ENERGY
RETURN ON EQUITY CALCULATION
WATER UTILITY GROUP

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) First Call Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.54%	2.54%	2.54%	2.54%	2.54%
Growth Rate	6.63%	5.31%	6.13%	6.11%	6.04%
Expected Div. Yield	2.62%	2.60%	2.61%	2.61%	2.61%
DCF Return on Equity	***9.25%***	***7.91%***	***8.74%***	***8.72%***	***8.65%***
Method 2:					
Dividend Yield	2.54%	2.54%	2.54%	2.54%	2.54%
Median Growth Rate	6.50%	6.00%	5.00%	5.00%	5.63%
Expected Div. Yield	2.62%	2.61%	2.60%	2.60%	2.61%
DCF Return on Equity	***9.12%***	***8.61%***	***7.60%***	***7.60%***	***8.24%***

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.97%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.46%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.50%
6	Comparison Group Beta	0.79
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.75%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.21%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.97%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.48%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.49%
6	Comparison Group Beta	0.79
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.53%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.01%

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data	Avg. Yield
Oct-15	2.50%
Nov-15	2.69%
Dec-15	2.61%
Jan-16	2.49%
Feb-16	2.20%
Mar-16	2.28%
6 month average	2.46%

5 Year Treasury Bond Data	Avg. Yield
Oct-15	1.39%
Nov-15	1.67%
Dec-15	1.70%
Jan-16	1.52%
Feb-16	1.22%
Mar-16	1.38%
6 month average	1.48%

Source: www.federalreserve.gov, Selected Interest Rates (Daily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.89%
Estimated Market Return	9.93%
Value Line Projected 3-5 Yr. Median Annual Total Return	12.00%
Average of Projected Mkt. Returns	10.97%

Source: Value Line Investment Survey for Windows retreived April 4, 2016

Comparison Group Betas:

Atmos Energy	0.80
LaClede Group	0.70
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.85
Southwest Gas	0.80
UGI Corp.	0.95
WGL Holdings	0.80
Average	0.79

Source: Value Line Investment Survey, March 4, 2016

CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.09%	5.09%	
Historical Market Risk Premium	5.01%	7.01%	6.19%
Gas Distribution Group Beta, Value Line	0.79	0.79	0.79
Beta * Market Premium	3.98%	5.56%	4.91%
Current 20-Year Treasury Bond Yield	2.46%	2.46%	2.46%
CAPM Cost of Equity, Value Line Beta	**6.44%**	**8.03%**	**7.37%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 40, 152, 157 - 158

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this
15th day of April 2016.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2018
COBB COUNTY, GEORGIA