BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

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PUBLIC SERVICE
COMMISSION

IN THE MATTER OF)

RATE APPLICATION BY) CASE NO. 20060-00464

ATMOS ENERGY/KENTUCKY DIVISION)

FILING REQUIREMENTS

VOLUME 2 OF 9

FILED IN SUPPORT OR PROPOSED

CHANGE IN RATES

DECEMBER 2006

Atmos Energy
Case No. 2006-00464
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Volume 2

RECEIVED
DEC 28 2006
PUBLIC SERVICE COMMISSION

Atmos Energy Kentucky
Case No. 2006-00464
Forecasted Test Period Filing Requirements

FR 10(9)(a)

Description of Filing Requirement:

Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

Please refer to the testimony of John Paris.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, John A. Paris, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

John Paris

STATE OF Kentucky
COUNTY OF Daviess

SUBSCRIBED AND SWORN to before me by John A. Paris on this the 18th day of December, 2006.

Jacqueline S Purcell
Notary Public
My Commission Expires: 11/15/2007

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORATION	)	

TESTIMONY OF JOHN PARIS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is John Paris. I am President of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky 42303.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Arts degree in History from Berea College in 1985. That same year, I became an operations aide for Western Kentucky Gas Company ("WKG"). WKG was acquired by Atmos in December of 1987 and is now part of Atmos' Kentucky/Mid-States division. I had worked in a variety of jobs for WKG during summer recess while attending college. After joining the company full time in 1985, I held positions of increasing responsibility before being named Assistant District Manager of the Bowling Green District in 1993. I became the Southern Colorado District Manager for Atmos in 1995. In 1997, I was named Vice President of Operations for the Colorado Region. In that position, I was responsible for safety, maintenance, construction, and customer service to Atmos'

Colorado customers. From 1999 to 2001, I was Chairman of the Atmos Marketing Council, which has the responsibility for developing and executing the Company's utility marketing strategy.

In 2001, I was named President of Atmos' Kentucky division and in February 2005, my responsibilities were increased to include Atmos' Mid-States division. As President of Atmos' Kentucky/Mid-States division, I have responsibility for customer services, operations, regulatory and community relations and the financial performance of those divisions.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No, but I have previously provided testimony before the Colorado Public Utilities Commission, the Georgia Public Service Commission, the Tennessee Regulatory Authority and the Missouri Public Service Commission in Atmos rate cases.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS CASE, AND, IF SO, WHICH REQUIREMENTS?

A. I am sponsoring the following filing requirements:

FR 10(1)(b)	Application Supported by a Fully Forecasted Test Period
FR 10(1)(b)(1)	Statement of Reasons
FR 10(1)(b)(3)	Certified Copy of Articles of Incorporation
FR 10(1)(b)(5)	Certificate of Good Standing
FR 10(1)(b)(9)	Statement on Customer Notice
FR 10(2)	Notice of Intent
FR 10(3)(a-i)	Form of Notice to Customers
FR 10(4)(c)	Manner of Notification
FR 10(4)(c)3	Notice of Publication in Newspapers of General Circulation
FR 10(4)(d)	Publisher Affidavits
FR 10(4)(f)	Notice to Customers Posted in Utility Places of Business
FR 10(5)	Notice of Hearing
FR 10(9)(a)	Statement of Officer in Charge of Kentucky Operations
FR 10(9)(e)1-3	Statement of Attestation

FR 10(11)(a-c) Request for Waiver of Certain Filing Requirements

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes.

II. OVERVIEW OF COMPANY WITNESS TESTIMONY

Q. PLEASE PROVIDE AN OVERVIEW OF THE PREPARED DIRECT TESTIMONY IN THIS PROCEEDING.

A. My testimony will sponsor the application and provide the reasons that Atmos is filing for rate relief. I will also give a brief description of the history of the Company, including our present operations and service areas. Lastly, pursuant to KAR 5:001 Chapter 278, Section 10(9)(a), I will describe and explain the purpose of the existing programs Atmos has in-place to achieve improvements in its efficiency and productivity.

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY OF THE OTHER ATMOS WITNESSES IN THIS CASE.

A. Mr. Thomas H. Petersen, Director of Rates (Shared Services), will sponsor the determination of the revenue deficiency indicated in Atmos' projected cost of service.

Mr. Greg Waller, Vice President of Finance (Kentucky/Mid-States Division), will sponsor the projected test period cost of service and the assumptions on which the projections are based.

Mr. Robert R. Cook, Jr., Vice President – Technical Services (Kentucky/Mid-States Division), will sponsor the projected capital expenditures and the assumptions on which the projections are based. He will also sponsor the study supporting the proposed special service charges.

Mr. Joel R. Bradshaw, Director – Business Planning and Analysis (Shared Services), will sponsor testimony on how the Shared Services budgets are developed.

Mr. Daniel Meziere, Director of Accounting Services (Shared Services), will sponsor the Company's books and records, as well as sponsor testimony concerning the Company's Cost Allocation Manual (CAM).

Mr. James Cagle, Manager of Rates (Shared Services), will sponsor the Company's method of allocating shared services costs to the various Atmos divisions including the Kentucky/Mid-States Division.

Mr. Donald Roff, a consultant and President of Depreciation Specialty Resources, will sponsor the Company's depreciation study.

Ms. Laurie Sherwood, Vice President, Corporate Development and Treasurer (Shared Services), will sponsor our proposed capital structure and embedded cost of debt.

Dr. Donald A. Murry, a consultant with C. H. Guernsey & Company, will testify to the appropriate rate of return on equity.

Mr. Bernard L. Uffelman, a consultant with Deloitte & Touche, will sponsor the class cost of service study.

Mr. Gary L. Smith, Vice President – Marketing and Regulatory Affairs (Kentucky/Mid-States Division), will support the forecast of growth, volumes and revenues as used in the Company's projections and various cost studies. He will also address the proposed changes requested in our tariffs, including our proposal to establish an experimental Customer Rate Stabilization mechanism that will be easy to administer and ensure ratepayers more stable and equitable rates. Lastly, Mr. Smith will address will describe Atmos' gas supply function and procurement of gas and capacity.

Each witness in turn will describe those filing requirements that they are sponsoring. The Company's testimony and its Filing Requirements submittal combine to illustrate the need for the proposed rates and Atmos believes that its proposal is just and reasonable.

III. PURPOSE OF THIS PROCEEDING

Q. WHAT IS THE PURPOSE OF ATMOS' APPLICATION IN THIS PROCEEDING?

A. Atmos is seeking approval of an increase in revenues of $10,409,950. This represents a 4.6% increase in total revenues based on a forecasted test period twelve months ending June 30, 2008. Although we operate very efficiently, we are not achieving a fair return on our investment with the rates currently in effect. The proposed increase will allow the Company to establish new rates that will provide it a fair return and offset the continued plant investment we have made in our system.

Atmos' last filed for a rate increase in Kentucky in 1999. At the time of that filing Atmos had the lowest rates in the state and its rates have remained the lowest even after that case. Since then, several of the major gas utilities in the Kentucky have increased their rates twice while our rates have remained the same.

While Atmos continually makes every effort to control its expenses, a portion of the requested increase is necessary to cover increased costs for items such as salary and wage increases, increased medical costs and higher pension benefits. The increase to the bill of an average residential customer at current gas prices would be $3.90 per month. That equates to a 5.6% increase. I believe that this is a modest rate increase given that the Consumer Price Index has increased approximately 19.6% since our last rate filing and the Company has invested almost $74 million in new plant and equipment in its Kentucky operations during the same period.

Prompt and adequate rate relief is essential if we are to continue to provide high-quality, safe and reliable service to our customers and achieve a reasonable rate of return. Our present rates fall short of providing sufficient revenues to meet these requirements.

Q. WHAT RATE RELIEF ARE YOU REQUESTING IN THIS APPLICATION?

A. We are asking the Commission to approve new rate schedules that would increase our revenues to provide a projected rate of return of 8.82 % on a projected net rate base of $169,405,541.

Q. WHAT IS THE RATE OF RETURN ON COMMON EQUITY REQUESTED IN THIS APPLICATION?

A. We have requested a rate of return on projected common equity of 11.75 %.

Q. WHY DOES ATMOS NEED THIS RATE RELIEF?

A. The reasons are specifically enumerated in Filing Requirement FR 10(1)(b)(1). In a nutshell, since the test period used in Atmos' last rate case, Atmos has increased its net rate base by $38,921,382 million including construction work in progress. At the same time steady declines in customer usage caused by energy conservation, more efficient homes and appliances, and changes in lifestyles have reduced our annual margins by approximately $4.3 million. Atmos simply cannot continue to sustain higher plant and equipment costs while margins decline.

Q. OTHER THAN THE REQUESTED INCREASE IN RATES, WHAT MAJOR RATE PROPOSALS IS ATMOS MAKING IN THIS FILING?

A. Other than the requested increase in rates, we have two major rate proposals. One is our proposed experimental Customer Rate Stabilization mechanism. The other is our proposal to recover gas costs included in uncollectible accounts through the Gas Cost Adjustment. Although Company witness Mr. Gary Smith will address these proposals in depth in his testimony I would like to briefly discuss why I believe both of these proposals should be approved.

Q. PLEASE DISCUSS THE CUSTOMER RATE STABILIZATION (CRS) MECHANISM.

A. We are proposing an innovative, experimental Customer Rate Stabilization mechanism (CRS) that will provide for an annual review of the Company's cost of operations to ensure ratepayers more stable and equitable rates. The annual review conducted under the CRS will provide for both a backward looking review of Company's financial performance for the most recent calendar year as well as project the Company's revenue requirement for a prospective twelve-month period going forward. Based upon these reviews, the Company would then propose an annual net adjustment in rates to both true-up the revenues from the previous year and set rates for the prospective period. The proposed new rates and supporting schedules would be subject to review by the Commission and the Attorney General's office. Final authority for any increase in rates would rest with the Commission subject to a timetable prescribed in the CRS. The CRS mechanism is proposed for an experimental period of five years, with a review of that mechanism to be filed by the Company in conjunction with the fifth annual filing under the mechanism.

This CRS mechanism would provide a structure for regular consistent, financially transparent rate reviews that would be conducted at a very low cost and provide for customer rate protection. The mechanism would not only review the Company's financial performance for the past year but also set the proper rates for the next year. If the projected costs from the previous annual review varied from actual costs a simple true up at the end of the period would refund any over collection, assuring that the customer will never pay too much.

The purpose of the CRS mechanism is to ensure transparency of the Company's annual financial performance and ensure that rates paid by customers at any time will recover those revenues and only those revenues necessary to achieve the rate of return authorized in the Company's most recent general rate filing. The mechanism would apply the principles and rules that govern ratemaking and the calculation of appropriate rates in Kentucky on an annual basis to test the existing rates, and adjust the rates as needed. In other words, there would no doubt as to whether the Company's rates are fair, just and reasonable because the rates derived from this annual evaluation will be re-set to earn the Company's allowed return.

I believe this proposal supports the companies' historic legacy and long term goal of having the lowest rates in Kentucky, the lowest gas cost in Kentucky and the lowest total cost to the customer while maintaining exceptional customer service and a safe reliable system. The best combination of price, service and safety, giving the customer the best value, has always been Atmos' goal in providing this valuable utility service.

Q. PLEASE DISCUSS ATMOS' PROPOSAL TO RECOVER GAS COSTS INCLUDED IN UNCOLLECTIBLE ACCOUNTS THROUGH THE MONTHLY GAS COST ADJUSTMENT (GCA).

A. The Company is currently authorized to recover a certain amount for uncollectible accounts in base rates. This amount includes both the gas and non-gas portion components of the uncollectible accounts. No other component of gas cost is included in base rates and all other components of gas costs are collected through the GCA. Because the GCA is not utilized for recovery of uncollectible gas costs, the Company will inevitably either under collect or over collect these costs because they can never been estimated with complete accuracy, particularly given the recent volatility in gas costs. I believe that the cost of purchased gas remains a gas cost regardless of whether it is collected or goes uncollected and therefore, should be recovered through the GCA instead of base rates.

IV. AN OVERVIEW OF ATMOS ENERGY

Q. CAN YOU PROVIDE THE COMMISSION WITH A GENERAL DESCRIPTION AND BACKGROUND OF ATMOS' NATURAL GAS DISTRIBUTION BUSINESS IN THE UNITED STATES?

A. Yes. Atmos Energy is the largest pure natural gas distribution company in the United States. It delivers natural gas to approximately 3.1 million residential, commercial, industrial and public-authority customers in twelve states. Atmos has six gas utility operating divisions. They are located in Denver, Colorado (Kansas and Colorado division); Baton Rouge, Louisiana (Louisiana division); Jackson, Mississippi (Mississippi division); Lubbock, Texas (West Texas division); Dallas, Texas (Mid-Tex division); and Franklin, Tennessee and Owensboro, Kentucky (Kentucky/Mid-States division). In addition, Atmos has an operating division consisting of a regulated intrastate pipeline that functions only within the state of Texas.

Atmos' history dates back to 1906 in the panhandle of Texas. Over the years, through various business combinations and mergers, the company became part of Pioneer Corp., a large diversified West Texas energy company. In 1983, Energas Company, the natural gas distribution division of Pioneer and formerly known as Pioneer Natural Gas, was spun off and became an independent, publicly held natural gas distribution company. In October 1988, Energas changed its corporate name to Atmos Energy Corporation and began trading on the New York Stock Exchange.

Since 1986, Atmos has completed numerous significant acquisitions. In 1986, Atmos expanded its natural gas distribution business to Louisiana with the acquisition of Trans Louisiana Gas Company. In 1987, Atmos further expanded its operations by moving into Kentucky with the acquisition of Western Kentucky Gas Company. In 1993, Atmos acquired Greeley Gas Company's Kansas, Colorado and Missouri operations and, in 1997, it acquired United Cities Gas Company, which operated in eight states including Missouri. Atmos acquired the Missouri assets of Arkansas Western Gas Company known as Associated Natural Gas Company in 2000 and, in 2001, it completed its purchase of the assets of Louisiana Gas Service Company and LGS Natural Gas Company. In December of 2002, Atmos expanded its operations into Mississippi with the acquisition of Mississippi Valley Gas Company. Most recently, in 2004, Atmos acquired the natural gas distribution and pipeline operations of TXU Gas Company from TXU Corp. The operations acquired in this transaction serve approximately 1.5 million customers in the Dallas-Forth Worth metroplex and more than 500 other communities in north and central Texas.

Atmos' corporate offices are located in Dallas, Texas, and provide services such as accounting, legal, human resources, rates administration, procurement, information technology, and a customer support center. These centralized services are shared with the other Atmos operating divisions in order to avoid having to staff and maintain these functions at each division level. These centralized services are the technical and administrative services that would be required if each division was a stand-alone company today. Atmos believes that this structure gives it an economic advantage and enables it be a low-cost, high-quality service provider of natural gas. Each of the Company's six utility divisions has its own divisional office that is responsible for the day-to-day operations of that division.

Q. CAN YOU PROVIDE THE COMMISSION WITH A GENERAL DESCRIPTION AND BACKGROUND OF ATMOS' OPERATIONS IN KENTUCKY?

A. Yes. Atmos' Kentucky/Mid-States Division, in addition to serving customers in Kentucky, provides natural gas distribution service in Tennessee, Virginia, Georgia, Missouri, Illinois and Iowa. The Kentucky/Mid-States Division provides natural gas service to approximately 472,000 customers across the seven states in which it provides service.

Atmos serves approximately 173,000 customers in Kentucky. The customer base includes residential, commercial and industrial customers. We have a Kentucky-based work force of approximately 230 employees. Our utility plant in Kentucky includes over 3,900 miles of transmission and distribution lines. I have included a map of Atmos' Kentucky service territory as Exhibit JP-1.

V. THE COMPANY'S EFFICIENCY AND PRODUCTIVITY

Q. PURSUANT TO KAR 5:001 CHAPTER 278, SECTION 10 (9)(A), PLEASE DESCRIBE AND EXPLAIN THE PURPOSE OF THE EXISTING PROGRAMS ATMOS HAS IN-PLACE TO ACHIEVE IMPROVEMENTS IN ITS EFFICIENCY AND PRODUCTIVITY.

A. The most significant changes we have made to achieve improvements in efficiency and productivity has been the series of mergers and acquisitions Atmos has undertaken since our last rate filing in Kentucky. Atmos has more than tripled in size through acquiring gas utilities in Louisiana, Missouri, Mississippi and Texas. These acquisitions have been instrumental in Atmos drive to achieve greater economies of scale and keep its costs, and therefore its rates, among the lowest in the industry. For example, Atmos now has over 2 million additional customers over which to spread its Shared Services (centralized) costs. Hence where in 1999, the Kentucky division bore approximately 17 percent of Atmos' Shared Services operations and maintenance (O&M) costs, today, Kentucky's share is closer to 5 percent. Base period Shared Services O&M cost allocated to Kentucky has declined from $8.3 million in the 1999 base period to $6.7 million for the base period in this case. That decline equates to a reduction in Shared Services O&M cost of $8 per customer since 1999.

Q. HAVE YOUR ACQUISITIONS SERVED TO ONLY REDUCE KENTUCKY'S SHARE OF CORPORATE ADMINISTRATIVE COSTS?

A. No. While Shared Services do encompass corporate administrative services which are most efficiently performed on a centralized basis such as accounting, treasury, investor relations, human resources, legal, gas supply, gas control, and rates, Shared Services also include important customer service costs. For example, our Centralized Call Center, SCT Banner billing software and related information technology systems are all Shared Services costs. These functions directly impact the efficiency and quality of our customer service. Atmos has utilized these common assets and the personnel who manage these systems to standardize its customer service business model across all divisions to maximize the number of employees and assets available to meet our needs at any time.

Q. OTHER THAN ACQUISITIONS, WHAT OPERATIONAL PROGRAMS HAS ATMOS UNDERTAKEN TO ACHIEVE EFFICIENCY AND PRODUCTIVITY?

A. Since our last rate filing in 1999, Atmos has undertaken substantial investments in a number of technologies to ensure that it provides the best and most efficient customer service possible. The technologies include our Customer Support Center, Banner billing software, Information Technology Infrastructure and Business Process Changes. Since 1999, Atmos has continued to improve its customer service platforms with second and even third generation technological upgrades. Each additional investment has served to enable the Company to provide customers with the best possible service at the lowest possible cost. These enhancements facilitate customer service through the streamlining of billing inquiries and service orders, allow for efficient billing and processing of customer payments and provide support to the Company's Customer Support Center. This technology provides ratepayers with many benefits including, but not limited to:

- Availability of customer service representatives 24 hours and seven days a week.
- Enhanced ability to respond quickly to leaks and other safety related events.
- More accurate bills.
- Faster response to service requests.
- More efficient use of labor and materials
- Ability for customers to make check and credit card payments by telephone or payments using bank drafts
- Enhancements to Company's ability to monitor the quality of its customer service.

Q. PLEASE DESCRIBE THESE ENHANCEMENTS IN GREATER DETAIL.

A. The key enhancement related to our Customer Service initiative in 1999 and 2000 was the implementation of a Customer Information System (CIS) using SCT Banner software. The CIS facilitates customer service and accounting functions through the streamlining of billing inquiries and service orders, and allows efficient billing and processing of customer payments in all of Atmos' operating jurisdictions. In addition, CIS provides support for Atmos' Customer Support Center. The Customer Support Center accepts service order requests, answers billing and other customer inquiries as well as emergency calls 24 hours a day, 7 days a week. Further, the Customer Support Center provides for a system that better measures the quantity and content of customer calls, as well as the quality of service provided to customers when they call. This includes recording of customer calls, the measurement of call lengths, and the tracking of the number and type of calls by the hour, day, week and month. This enables Atmos to continually monitor the quality of its customer service and also assists in forecasting call loads and scheduling customer service personnel to ensure that the Customer Support Center operates as effectively and efficiently as possible. The system also provides Atmos with the enhanced ability to respond to leaks and other safety-related events faster than ever before by enabling all field service employees to receive orders while in the field.

Q. ARE THERE OTHER ASPECTS OF THESE ENHANCEMENTS TO CUSTOMER SERVICES THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. The system also allows customers to pay their bills using bank drafts. Customers who opt for this service have a draft issued to their bank and their bills are then deducted from their bank account each month. This has proven to be an attractive option for customers who do not want to spend the time and postage each month required to pay their gas bill. In addition, the system uses Speedpay and Telepay to provide customers with alternative means of paying their bills. Speedpay allows the Customer Service Associates at the Customer Support Center to participate in check-by-phone transactions with customers. Telepay is similar, but it uses an Interactive Voice Response system to enable customers to pay their bills using their credit cards. While not every customer chooses these services, Atmos has found many customers prefer the ease and convenience they offer.

The system also provides customers with the ability to choose the due date of their bills. This is important to many customers, particularly those on fixed incomes, because it allows them to plan their payments at the time that best meets their needs and monthly budgets. In addition, the system allows for summary billing which enables the Company to send customers with service at multiple locations one (1) bill.

Q. PLEASE DESCRIBE SOME OF THE OTHER MEASURES ATMOS HAS IMPLEMENTED TO UPGRADE CUSTOMER SERVICE TO ITS KENTUCKY CUSTOMERS.

A. Atmos also introduced technological enhancements used by its field personnel including the use of hand-held computers known as ITRONs for automated meter reading and mobile data terminals (MDT) installed in the vehicles of our field service employees. The ITRONs eliminate the need for meter readers to carry meter reading sheets and enter each meter reading on those sheets. Instead, the employee simply reads the meter and enters the readings into the ITRON. This reduces the potential for errors in customers' bills. Atmos has further controlled the cost of meter reading in Kentucky over the past four years by estimating summer-time meter readings during May, July and September.

Each MDT is equipped with the capability to communicate directly with the Customer Support Center. It is used by our service technicians in the field to process field service work orders while on-site or traveling in the field. Field service work orders are transmitted directly to the MDT units, thereby eliminating the paperwork order system and the delay inherent in having to go through a third-person dispatcher. Further, the MDTs allow our field service employees to be even more responsive to customers by providing them with direct access to customer information stored in Atmos' customer database. Once the field service employee completes the work detailed on the work order, he is able to input the work order or completion information in his vehicle rather than submitting a bundle of paperwork at the end of each shift. In the case of emergency work orders, the MDTs enable field service employees to receive the orders directly while already in the field and thereby provide a faster response. In short, the MDTs enable Atmos to respond more directly, more efficiently, and more quickly to our customer's needs. There is far less chance of orders going astray or being mis-communicated and field service employees are freed up to spend more time in the field meeting the needs of our customers and less time doing cumbersome paperwork. We have recently upgraded to satellite technology some of our MDT's in certain rural areas in order to ensure that our service technicians have ready access to our network and are not delayed in their work by failing cellular signals.

Q. HAVE THESE ENHANCEMENTS CONTRIBUTED TO MORE EFFICIENT AND IMPROVED CUSTOMER SERVICE?

A. Absolutely. For example, these technological improvements allowed us to provide Same Day Service, whereby utilizing specialized dispatching software, we are been able to complete standard service requests within two hours where facilities are already in-place. Our web-based service enhancements allow customers a host of options for bill payment including the use of bank drafts, credit cards and payment online. Atmos' experimentation with freestanding Kiosks allows customers to make bill payments without requiring the assistance of Company personnel. Use of Equifax technological enhancements allows us to research customer credit information online, and apply more consistent collection practices.

Clearly, the investment that Atmos has made in enhanced technology has been a driving force behind its continued success as a low-cost, high-quality provider of natural gas service and is one of the reasons it has not required a rate increase since 1999.

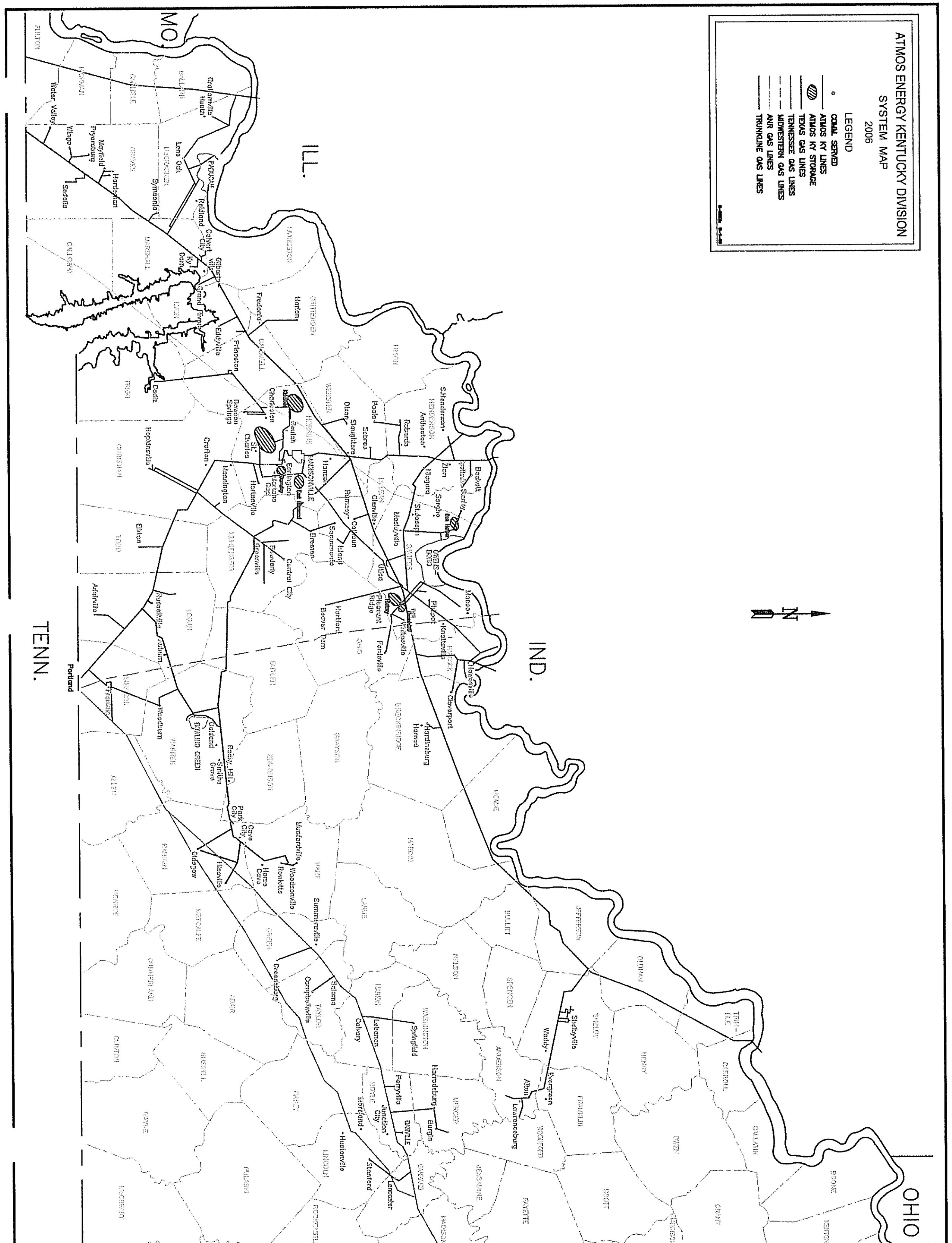
VI. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS?

A. Yes. It is my opinion that the rates requested in this filing are just, reasonable, and in the public interest and I would encourage the Commission to provide prompt and adequate rate relief. I believe that it is particularly valuable that the Company's request proposal to implement an easy to administer, experimental Customer Rate Stabilization mechanism be granted in order ensure ratepayers more stable and equitable rates in the future. I also believe that the volatility in gas costs that we have seen in recent years and the difficulty we have experienced in collecting such costs supports the recovery of gas costs included in uncollectible accounts through the GCA.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.


ATMOS ENERGY KENTUCKY DIVISION
SYSTEM MAP
2006
LEGEND
COMM. SERVED
ATMOS KY LINES
ATMOS KY STORAGE
TEXAS GAS LINES
TENNESSEE GAS LINES
MIDWESTERN GAS LINES
ANR GAS LINES
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Thomas H. Petersen, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

Thomas H. Petersen

STATE OF Texas
COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by Thomas H. Petersen on this the 18th day of December, 2006.

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

Ethel Z. Taylor
Notary Public
My Commission Expires: August 13, 2010

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No 2006-00464**
ATMOS ENERGY CORPORATION	)	

TESTIMONY OF THOMAS H. PETERSEN

Q. Please state your name, job title and business address.

A. My name is Thomas H. Petersen. I am Director of Rates for Atmos Energy Corporation ("Atmos" or "Company"), 5430 LBJ Freeway, Dallas, Texas 75240. I am responsible for rate studies of the Company's gas utility operations in 12 states including Kentucky.

Q. What is your educational background and professional experience?

A. I received a Bachelor of Science degree in accounting from the University of Nebraska at Omaha and a Master of Arts degree with a major in finance from the University of Iowa. I am a Chartered Financial Analyst. From July 1980 through March 1989, I was employed in Rates and Tariffs Division of the Kentucky Public Service Commission. I was Manager of Rates and Revenue Requirements for Atmos from April 1989 through September 1997. I was Director of Price Policy and Administration from October 1997 through September 1998. I have been in my current position since October 1998.

Q. Before which regulatory Commissions have you previously testified?

A. I have filed testimony before the Kentucky Public Service Commission, the Texas Railroad Commission, the Louisiana Public Service Commission, the Colorado Public Utilities Commission, the Kansas Corporation Commission, the Georgia Public Service Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Tennessee Regulatory Authority, and the Virginia State Corporation Commission.

Q. What is the scope of your testimony in this proceeding?

A. I am responsible for the calculation of the Company's revenue deficiency and the rate base in this docket and in that regard I am sponsoring the following Filing Requirements (FR):

FR 10 (8) (c)	Capitalization and net investment rate base
FR 10 (8) (f)	Reconciliation of the rate base and capitalization.
FR 10 (9) (h)	(2) Balance sheet, (3) cash flow statement and (12) rate base
FR 10 (10) (a)	Derivation of the requested revenue increase (Schedule A).
FR 10 (10) (b)	Rate base summary for the base and test period (Sched. B).

I am also sponsoring the ratemaking adjustments included in Schedule C-2 filed in compliance with filing requirement FR 10 (10) (c).

Q. Do you adopt these Filing Requirements, and their associated schedules, and make them part of your testimony?

A. Yes.

Q. What is the source of the data used to complete the Filing Requirements that you are sponsoring?

A. The source of the data includes the accounting books and records of the Company which are being sponsored by Company witness Mr. Dan Meziere along with information provided by the following witnesses to this proceeding: Mr. Rad Cook (capital budget additions); Mr. Greg Waller (expense forecast); Mr. Gary L. Smith (revenue, gas cost and margin forecast; sales statistics); Mr. Don Roff (depreciation rates); Dr. Don Murry (cost of equity); Mr. James Cagle (allocations and taxes) and Ms. Laurie Sherwood (capital structure, debt cost rates and composite cost of capital).

The detail concerning how this information was derived is found in the testimony of these witnesses. The data and information provided by these witnesses is the best available information and was developed consistent with sound ratemaking practices. Further, the methods that I used to determine the Company's revenue requirement and rate base in this docket are consistent with the Company's approach in prior cases and with past Commission practice. The items included in rate base in this case are the same as those in the Company's last filing except that investment in construction work in progress for which an allowance for funds used during construction was not recorded was included in this case. Including such construction work in progress amounts is consistent with the Commission's treatment in previous Company cases.

Revenue Deficiency

Q. What is the amount of Atmos' revenue deficiency?

A. The amount of revenue deficiency Atmos seeks to recover in its proposed rates is $10,409,950, as shown on line 8 of Schedule A. This deficiency is based on the forecasted test period twelve months ended June 30, 2008, an average rate base of $169,405,541, and a required rate of return on rate base of 8.82%. The required return and projected capital structure are presented in FR 10 (10)(j) and discussed in the testimony of Ms. Laurie Sherwood.

Q. What is the source of forecasted test period adjusted operating income of $8,774,577, shown on Schedule A, line 2.

A. The forecasted test period adjusted operating income is determined in Schedule C and discussed in Mr. Waller's testimony.

Rate Base

Q. How did you determine the level of rate base for the test period?

A. The test period rate base of $169,405,541 is summarized in Schedule B-1, and detailed in Schedules B-2 through B-6. Each component of the test period rate base is a thirteen month average forecasted amount, unless noted otherwise. The components of rate base are: net plant in service, construction work in progress, cash working capital calculated using the 1/8 operation and maintenance expense method, plus an allowance for other working capital items consisting of materials and supplies, gas stored underground, and prepayments, less customer advances for construction and deferred income taxes.

Q. How was the test year gross plant in service projected?

A. I began with actual per books gross plant as of September 2006 including allocations of shared plant as discussed by Mr. Cagle in his testimony. For the months of fiscal year 2007 (October 2006 through September 2007) I added budgeted plant additions and deducted projected plant retirements. For the months of October 2007 through the end of the test year I added plant additions in amounts 5% greater than the fiscal 2006 additions to reflect the expected growth in spending consistent with the company's five year plan. Projected plant retirements were generally based on the level of retirements recorded in fiscal year 2006. Routine retirements in each month of fiscal 2006 were projected to continue at the same level in the same month in future years. More unusual retirements were not projected to continue at the same level. For example, in November 2006 (just after the conclusion of fiscal year 2006) the Company recorded some retirements for shared assets that had gone out of service in recent years. I included those retirements in November 2006 and projected smaller retirements equal to one-fourth of the November 2006 retirements into November 2007 and 2008.

Q. How was the test year accumulated depreciation projected?

A. I began with actual per books accumulated depreciation as of September 2006 including allocations as discussed by Mr. Cagle in his testimony. For the months of October 2006 through the end of the test year, I added budgeted depreciation and deducted the same retirements that were projected for gross plant. The budgeted depreciation amounts are discussed in Mr. Waller's testimony.

Q. How did you determine the amount of test year construction work in progress to include in rate base?

A. I began with actual per books construction work in progress as of September 2006 including allocations. I reduced that amount to exclude projects for which an allowance for funds used during construction was recorded. I concluded that the September 2006 construction work in progress balances were reasonable estimates of future construction work in progress balances through the forecasted test year. By leaving the amount of construction work in progress level through the end of the test year I in effect was assuming that projected capital projects would be closed to gross plant at the same rate at which capital costs were incurred and booked to *construction work in progress*.

Q. How was the test year amount of material and supplies determined?

A. I calculated the amount of materials and supplies in the forecasted period based on actual amounts booked in fiscal year 2006. For example, the amount of materials and supplies projected for June 2007 was equal to the average amount booked for June and July of 2006. The Company does not anticipate a significant change in the amount of materials and supplies in the test year. The calculation method maintains the historic level of materials and supplies while smoothing out any historic month to month fluctuations.

Q. How was the amount of gas in storage determined?

A. The projected amount of gas in storage is discussed in Mr. Smith's testimony.

Q. How was the test year amount of prepayments determined?

A. I calculated the amount of prepayments in the forecasted period based on actual amounts booked in fiscal year 2006. The Company has no expectation that these amounts will change in the test year. For example, the amounts projected for prepaid rent remain the same as the actual 2006 amounts pursuant to leases and the amounts projected for prepaid KPSC fees assume that the same fees will be incurred in June of 2007 and 2008 as were incurred in June of 2006 and that the amounts also will continue to be amortized over twelve months.

Q. How did you project the amount of test year customer advances for construction?

A. I calculated the amount of customer advances in the forecasted period based on actual amounts booked in fiscal year 2006. For example, the amount of customer advances projected for June 2007 was equal to the average amount booked for June and July of 2006. The Company does not anticipate a significant change in the amount of customer advances in the test year. The calculation method maintains the historic level of customer advances while smoothing out any historic month to month fluctuations.

Q. How did you determine the amount of test year deferred income taxes to include in rate base?

A. I included the amount of deferred taxes projected by the company's tax department as adjusted by Mr. Cagle.

Q. Did you prepare a reconciliation of test year rate base and capitalization?

A. Yes. To comply with section 10 (8) (f) of 807 KAR 5001 I prepared the reconciliation in the attached Schedule FR 10(8)(f). It shows the differences between the test year average rate base and test year end capital that result from using 13 month averages in rate base, certain balance sheet items not being included in rate base and amounts included in rate base for particular categories such as deferred taxes, that differ from the amount included on the balance sheet.

Adjustments

Q. Please describe the ratemaking adjustments in Schedule C-2.

A. Schedule C-2 contains three ratemaking adjustments and the related income tax effects. The first adjustment removes Owensboro Country Club dues and related expenses from test year distribution operating expense. The second adjustment removes sales and promotional advertising from test year sales expense. The final adjustment removes an estimated $100,000 of certain management expenses from test year administrative and general expense. The company believes that these expenses should be borne by shareholders.

Q. Does this conclude your testimony?

A. Yes.

Atmos Energy Corporation, KY
Case No. 2006-00464
Reconciliation of Forecasted Test Year Rate Base to Kentucky Capital
Forecasted test year ended June 30, 2008

Line No.	Description	Test Period Rate Base as filed	Rate Base June 30, 2008	Adj from 13 month average	Adj due to rate base methodology	June 30, 2008 Balance Sheet
1	Gross Plant	322,898,092	331,265,384	8,367,292	136,504	331,401,888
2	Accumulated Deprec.	(150,189,986)	(155,401,549)	(5,211,563)	-	(155,401,549)
3	CWIP	1,543,040	1,081,678	(461,362)	2,535,653	3,617,331
4						
5	Cash Working Capital	2,605,840	2,605,840	-	(2,605,840)	-
6	Materials & Supplies	575,401	611,728	36,327	-	611,728
7	Storage Gas	21,792,727	23,598,275	1,805,548	-	23,598,275
8	Prepayments	799,159	984,837	185,678	-	984,837
9						
10	Customer Advances	(3,685,193)	(3,668,454)	16,739	-	(3,668,454)
11	Deferred inc. tax	(26,933,538)	(26,722,048)	211,490	-	(26,722,048)
12						
13	Rate Base	169,405,542	174,355,691	4,950,149	66,317	174,422,008
14						
15	Assets not in Rate Base					
16	Cash & temporary investments					428,242
17	Account receivable					10,810,000
18	Other current assets (except prepaids)					(523,475)
19	Deferred debits					13,785,347
20	Liabilities & Deferrals not in Rate Base					
21	Current Liabilities (excl. Notes Payable)					(29,955,425)
22	Deferred Credits (excl. Customer Advances)					-
23						
24	Total Capitalization (net of intercompany balances)					168,966,697

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF)
RATE APPLICATION OF) Case No. 2006-00464
ATMOS ENERGY CORPORATION)

CERTIFICATE AND AFFIDAVIT

The Affiant, Gregory K. Waller, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

Gregory K. Waller

STATE OF Tennessee
COUNTY OF Williamson

SUBSCRIBED AND SWORN to before me by Gregory K. Waller on this the 18th day of December, 2006.

TRACY A. OLIVE NOTARY PUBLIC AT LARGE WILLIAMSON COUNTY, TN

Tracy A. Olive
Notary Public
My Commission Expires: 3/22/08

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORATION	)	

TESTIMONY OF GREGORY K. WALLER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gregory K. Waller. I am Vice President of Finance for the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos" or the "Company"). My business address is 810 Crescent Centre Drive, Suite 600, Franklin, TN 37067.

Q. PLEASE STATE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in economics from Dartmouth College in 1994 and an MBA degree from the University of Texas in 2000. I worked as a management consultant from 1994 to 2003 at Harbor Research in Boston, MA (1994-1996) and Towers Perrin in Dallas, TX (1997 – 2003). I joined Atmos Energy in 2003 in the Planning and Budgeting Department in Dallas. I became Vice President of Finance for the Mid-States Division in November, 2005 and added Kentucky to my scope of responsibility in April, 2006.[1]

Q. WHAT ARE YOUR RESPONSIBILITIES AT ATMOS?

A. I am responsible for monitoring and analyzing the financial performance of the Kentucky Mid-States Division, and implementing necessary actions based on those results. I also direct the development of the Division's annual budget. Other

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[1] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated and are now, in effect, one division – the Kentucky/Mid-States Division. "Division" as used in my testimony means the Company's Kentucky/Mid-States Division. "Kentucky" when used in my testimony, unless indicated otherwise, refers exclusively to the Company's operations in Kentucky.

responsibilities include establishing and maintaining policy, procedures, and controls to ensure compliance with Corporate Accounting policies, Generally Accepted Accounting Principles (GAAP), and regulatory requirements.

Q. HAVE YOU TESTIFIED BEFORE THIS OR ANY OTHER REGULATORY COMMISSION?

A. I have never testified before this Commission. I testified in Docket 05-00258 before the Tennessee Regulatory Authority in 2006.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS PROCEEDING?

A. Yes. I am sponsoring the following filing requirements:

FR 10(8)(a)	Forecasted financial data presented as pro forma adjustments to the base period
FR 10(8)(b)	Forecasted adjustments limited to twelve (12) months immediately following the suspension period
FR 10(9)(c)	Description of all factors used in preparation of the forecast test period – income statement, operation and maintenance expenses, employee and labor expenses
FR 10(9)(d)	Annual and monthly budget for the 12 month period preceding filing date, the base period and the forecast period.
FR 10(9)(h)1	Operating income statement
FR 10(9)(h)9	Employee Level
FR 10(9)(h)10	Labor cost changes
FR 10(9)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast
FR 10(9)(o)	Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available.
FR 10(10)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and individual account

FR 10(10)(d)	Summary of jurisdictional adjustments to operating income
FR 10(10)(f)	Summary schedules for the base and forecast periods of various expenses
FR 10(10)(g)	Analysis of payroll costs
FR 10(10)(i)	Comparative income statements, revenue and sales statistics most recent five years, base period, forecast period and two (2) years beyond
FR 10(10)(k)	Comparative financial data and earnings measures

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM A PART OF YOUR TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will describe the Company's Operating and Maintenance expense (O&M) budgeting process used by Atmos and the process of control and monitoring of O&M variances. I will also present the forecasted test year budget for O&M, depreciation expense, and taxes other than income taxes. I will also present the budgeted Shared Services O&M as they pertain to the Kentucky Mid-States Division.

II. O&M BUDGETING PROCESS

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S O&M BUDGETING PROCESS?

A. The objectives of the Company's O&M budgeting process are to: (1) formalize the process of identifying the anticipated costs of operating and maintaining Atmos' systems each year; (2) ensure that all policies and procedures associated with the annual budgeting process are consistently adhered to by the functional managers and officers; (3) assess the appropriateness of routine maintenance requirements and non-capital expenditures proposed by the functional managers and officers to ensure that the amounts do not exceed a level necessary to deliver safe, reliable and efficient natural gas service to the Company's customers; and (4) ensure that the O&M budget properly reflects our strategic operational and financial plans. These objectives are applicable to the Company as a whole as well as to its various division, state and local level operations.

Q. CAN YOU DESCRIBE THE COMPANY'S O&M BUDGETING PROCESS?

A. Yes. O&M costs are budgeted on a fiscal year basis, which begins on October 1 of each year (consistent with the seasonal operations of our business) and runs through September 30 of the following year. Preparation of operating and construction budgets for a fiscal year formally begins in late May of each year and culminates with completion of final budgets in late August, just prior to the beginning of the fiscal year. Budget preparation is based on meeting the four objectives described above. Budgets are approved at multiple levels beginning with supervisor/managers up through division leadership. Additional reviews are performed by corporate executive operations management and their staff. High level reviews of the division budgets are also performed by the Company's senior executives who are presiding members of the Company's Management Committee. The Board of Directors must review and approve the total Company budget before finalization and implementation. This approval typically occurs in September of each year.

Q. WHAT ROLE DOES THE O&M BUDGETING PROCESS PLAY IN THE COMPANY'S FINANCIAL PLANNING?

A. Atmos' Planning and Budgeting Department is responsible for financial planning at the enterprise level. That department receives direction from the Board of Directors concerning forward-looking financial objectives for the Company. Planning and Budgeting is responsible, with significant input and collaboration from division leadership, for translating those enterprise targets into a financial plan for each division and rate jurisdiction. It is the collaboration between Planning and Budgeting and division leadership that ensures that all four of the objectives described above are met each year. Spending targets are established as a result of this collaboration.

Q. WHAT IS YOUR ROLE IN THIS PROCESS?

A. My role is to facilitate the budget process within the Kentucky/Mid-States Division that confirms the operational feasibility of the targets and produces an O&M budget consistent with the Company's processes and goals described above. My department communicates certain budget guidelines such as average wage increase percentages and anticipated benefits rates to managers and supervisors (cost center owners). Each cost center owner is responsible for building his or her department's budget and submitting it for review by me and approval along the appropriate approval chain. My department provides support to and often asks for clarifying information from cost center owners as needed to explain significant variances from the prior year. In addition, we budget several items on behalf of the entire Division such as bill print fees, gas supply services, insurance costs, bad debt provision, etc. An iterative process involving Division leadership (including myself), my department and the cost center owners ultimately produces an O&M budget that meets the needs of our operations, ensures that we operate safely, reliably and efficiently, and allows our Division to contribute to the financial success of Atmos. This process is used to develop the direct O&M budget for Kentucky, as well as the Division's general office O&M budget. A portion of the Division's general office O&M budget, as hereinafter discussed, is allocated to Kentucky in accordance with the allocation methods addressed in the direct testimony of Company witnesses Daniel M. Meziere and James C. Cagle.

Q. ARE YOU FAMILIAR WITH THE COMPANY'S SHARED SERVICES GROUP?

A. Yes. The Company's Shared Services Unit (often referred to as SSU) provides central support functions to the Division, including Kentucky, such as accounting, legal, tax, information technology, customer support (call center, billing, collections), etc. All of this is more particularly described in Mr. Cagle's testimony.

Q. ARE YOU INVOLVED WITH THE PREPARATION OF THE SSU O&M BUDGET?

A. Only insofar as the amounts which are budget by SSU departments impact the O&M budgets for the Division and for Kentucky, as well as interfacing with appropriate SSU department heads with respect to any additional services which may be required from SSU for the Division or for Kentucky.

Q. SO FAR YOU HAVE DESCRIBED THE O&M BUDGETING PROCESS. CAN YOU EXPLAIN HOW THE BUDGET IS PREPARED WITHIN THE PARAMETERS OF THIS PROCESS?

A. Yes. The O&M budget is prepared by type of cost element, such as labor, benefits, transportation, rents, office supplies, etc. Within each cost element we budget expenses at the sub-account level. The prior year's actual costs, year to date actual costs and budgeted costs for the remainder of the fiscal year are used as guidelines for budgeting by functional managers and officers. The budgets are prepared using a web based software tool called PlanIt. This tool allows cost center owners to enter their budgets and allows my department and Division management to review budgets using a number of standard and ad hoc reports.

Q. ARE THESE BUDGETS PREPARED BY FERC ACCOUNT?

A. No. In our experience, FERC accounts do not provide a sufficient level of detail to enable us to understand the costs within each account. For budgeting purposes (and subsequent managing of expenses), we need individualized expense types that relate to the operation of each cost center. FERC accounts do not provide that level of detail. However, when we spend, we do identify our expenditures by FERC account as well as expense type. This provides a timely analysis of the type of charges being expensed by FERC account.

Q. HOW DOES ATMOS CONVERT ITS O&M BUDGET BY COST ELEMENT INTO FERC ACCOUNTS?

A. To convert our budget and forecast to FERC accounts, prior year actual expenditures were downloaded from the general ledger by FERC account and cost element. A calculation was then made to determine within each cost element type the percentage of spending attributable to each FERC account. Each percentage factor was then applied to the fiscal year 2007 budget and test period forecast by cost type to develop a budget and test period forecast by FERC account.

Q. WERE THERE ANY RECENT ORGANIZATIONAL CHANGES WITHIN THE DIVISION WHICH IMPACT THE PREPARATION OF THE O&M BUDGETS FOR EITHER THE DIVISION OR FOR KENTCUKY?

A. Yes. As alluded to earlier in my testimony[2], effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were combined into a single operating division (the "Kentucky/Mid-States Division"). Combining the two divisions has allowed for some restructuring of responsibilities among the officers and managers of the two divisions.

[2] *See* footnote 1, *infra*.

The Company began implementing some of these changes in early 2005 and progressively made further changes during 2006.

Q. PLEASE DESCRIBE THE CHANGES TO WHICH YOU REFER.

A. Upon the retirement of the Mid-States Division President in January 2005, John Paris, the President of the Kentucky Division and a Company witness in this case, assumed responsibility as President over both divisions. In addition, the Kentucky Vice President of Finance retired in April 2006, and the decision was made to continue to operate both divisions with one Vice President of Finance. Similarly, the Mid-States Vice President of Technical Services retired in October, 2006 and we now operate the Division with one Vice President of Technical Services.

Prior to combining the divisions, the Kentucky and Mid-States Divisions each had two Vice Presidents of Operations. In June 2006, the Mid-States Division's Eastern Region Vice President of Operations retired, allowing for a significant reorganization of our operating regions beginning October 1, 2006. The newly combined Division now operates with three Vice Presidents of Operations who are responsible for the Northern, Central, and Southern regions. The Northern Region includes parts of Kentucky, Missouri, Illinois and all of the Company's service territory in Iowa. The Central Region includes the remaining parts of Kentucky, Missouri, Illinois, and Union City, Tennessee. The Southern Region includes the remaining parts of Tennessee, and all of the Company's service territories in Virginia and Georgia. Some managers under these officers have also been assigned new areas of responsibility.

Q. ARE THERE ANY OTHER ORGANIZATIONAL CHANGES WHICH ARE PLANNED?

A. Currently, the changes I have described are the only planned changes that have or will take effect. There are no other plans to close or consolidate any offices, move employees, or make other physical changes to the operations of the Division at this time. Any other increased efficiencies and cost savings that can be achieved from the combination of the two divisions will be carefully considered and implemented if found to be of benefit to the Company and its customers.

Q. DID THE ORGANIZATIONAL CHANGES YOU HAVE DESCRIBED IMPACT COMMON COST ALLOCATION?

A. Yes. Combining the Kentucky Division, a single state division, with Mid-States, a multi-state division, necessitated accounting changes as well. The Kentucky Division leadership and division support people (the Kentucky Division's "general office"), located in Owensboro, had historically charged expenses to the same rate jurisdiction as the operations personnel because the state, rate jurisdiction, and division were the same. The Mid-States general office, located in Franklin, Tennessee, was accounted for as a separate rate jurisdiction that allocated costs to the six states that made up the division. Effective October 1, 2006, the Mid-States and Kentucky division general offices were combined, for accounting purposes, to create one central rate division that houses all of the newly combined division's administrative costs. In other words, the Company will keep these offices open physically, but will only house and allocate costs from one central administrative rate division. We use a composite allocation factor to allocate common costs to all seven states served by the new general office rate division. The composite factor methodology is further described in the direct testimony of Mr. Cagle. All costs charged to the new division general office can and should be allocated to the seven states using the composite allocation factor because each Division officer and all other employees in the general office rate division provide direction, administrative support, and various services for all states throughout the combined Kentucky/Mid-States Division.

Q. WHAT AFFECT DID THE CHANGES YOU HAVE DESCRIBED HAVE UPON THE ALLOCATION OF SSU COMMON COSTS?

A. These changes also impact the amount of common costs allocated to the Division by SSU as well as the amount of SSU common costs ultimately allocated to Kentucky. The complete SSU common cost allocation process from SSU to the Division and then ultimately to the operating rate divisions within the Division (although briefly described above) is more particularly described in Mr. Cagle's testimony.

Q. HOW DO THESE CHANGES TO COMMON COST ALLOCATION AFFECT THE O&M BUDGETS FOR THE DIVISION AND FOR KENTUCKY?

A. The fiscal year 2007 budget, booking of actual expenditures and forecasted test period O&M reflect the new divisional structure and changes described above.

III. O&M CONTROL AND MONITORING

Q. DOES THE COMPANY EMPLOY ANY METHODOLOGY TO MONITOR AND CONTROL O&M ACCORDING TO BUDGETED LEVELS?

A. Yes. Atmos utilizes variance monitoring to ensure financial quality control of O&M expenses by formalizing the analysis of variances by cost type and cost center. On a quarterly basis, we present our Division's actual to budget variances with explanation to the Company's Management Committee, SSU department heads, select Board of Directors members and external auditors at a formal Quarterly Performance Review. The goal is to keep all levels of management informed of our O&M spending in comparison to budgeted amounts, in order to allow management to react to unanticipated events on a timely basis.

Q. ARE O&M VARIANCES EVALUATED MORE FREQUENTLY THAN ON A QUARTERLY BASIS?

A. Yes. My department conducts a thorough review of O&M actual to budget variances each month.

Q. PLEASE DESCRIBE YOUR MONTHLY VARIANCE REVIEW PROCESS.

A. We begin by examining, at the Division level, significant variances by cost type (labor, benefits, materials, rents, etc.). Significant variances are researched until an explanation is found. Reasonable explanations could include events that affected the entire Division or a particular cost center or region. In some cases, clarifying information is sought from cost center owners to explain unusual variances or transactions. For some cost types, clarifying analysis is provided by SSU departments. If errors are found, they are most often corrected in the current month's business. Occasionally, however, errors are discovered after the books are closed, and, depending on materiality, they are corrected in the following month's business.

Q. DOES ANYONE ELSE WITHIN THE DIVISION HAVE THE ABILITY TO MONITOR OR REVIEW O&M VARIANCES?

A. In addition to the research conducted by my department, each cost center owner has the ability to run variance reports throughout the monthly closing process. Because cost center owners are held accountable for significant variances to budget, they conduct their own research and often contact my department when they find errors or have questions about the expenses that were charged to their cost centers.

Q. WHAT CONTROLS AND REPORTING ARE INVOLVED IN THE MONTHLY CLOSE PROCESS REGARDING O&M VARIANCES?

A. Once the monthly books are closed, the SSU Financial Reporting department in Dallas publishes (electronically) the monthly Atmos Financial Package. This package details the financial performance for Atmos Energy at the corporate and each division level. For each division, the report includes a comparative income statement, operating statistics (volumes, total spending) page, O&M detail page, balance sheet highlights page and financial highlights page. The financial highlights page reports the Division's monthly and year-to-date (YTD) performance versus budget for net income, gross profit, direct O&M and capital spending. I provide narrative comments on this page to describe our monthly and YTD variances. Once complete, this Financial Package is available to all Atmos officers and Board members for review and is an official Sarbanes Oxley control document of the Company. Once the package is complete, I send an e-mail to the Director of Financial Reporting certifying that my department has conducted its thorough review of the Division's financial performance and the Financial Package and that we have addressed any issues present in that Package. The Company's external auditors look for that e-mail for evidence of Sarbanes Oxley compliance.

After meeting the Financial Package control requirement, my department publishes (electronically) detailed O&M reports that include monthly and YTD variances for each cost center and these reports are then made available to each cost center owner and their respective managers (managers, Division Vice Presidents, Division President). This activity ensures that each cost center owner receives the same information in the same format each month in a timely fashion in order to make operational decisions and manage our operations effectively and efficiently.

Q. HAS THE O&M VARIANCE MONITORING AND CONTROL PROCESS YOU HAVE DESCRIBED ENABLED KENTUCKY TO OPERATE REASONABLY WITHIN ITS BUDGET EACH YEAR?

A. Yes. As the table below demonstrates, actual O&M expenditures over the past five years have, with certain exceptions regarding benefits and bad debt expense, tracked closely to overall budgeted amounts.

Dollars in thousands

Fiscal Year	Actual $	Budget $	Over/(Under) $	Variance %	Variance % w/o Benefits and Bad Debt
2006	$19,874	$19,029	$845	4.4%	3.9%
2005	$18,618	$19,057	$(439)	-2.3%	-2.5%
2004	$16,076	$18,194	$(2,118)	-11.6%	-6.8%
2003	$17,092	$18,395	$(1,303)	-7.1%	-6.6%
2002	$16,745	$19,737	$(2,992)	-15.2%	-4.0%

Q. WHY DO YOU NOTE AN EXCEPTION FOR BENEFITS?

A. Due to the difficulty of estimating the cost of actual medical claims, benefit costs represent the most difficult item to budget accurately.

Q. WHY DO YOU NOTE AN EXCEPTION FOR BAD DEBT?

A. In both 2002 and 2004, we decided to adjust bad debt expense (reflected in O&M as "allowance for doubtful accounts") by adjusting the level of the reserve account maintained to cover bad debt write-offs. Each year, the SSU Accounting Department in Dallas analyzes Kentucky's reserve account and determines whether or not it is sufficient to cover potential future write-offs. In 2004 and 2002, the analysis showed that the balance in the reserve account was more than sufficient to cover potential write-offs. Therefore, the decision was made to reverse a portion of the O&M expense charged for allowance for doubtful accounts. Those entries totaled ($502,921) in 2004 and ($1,792,196) in 2002.

Q. DO YOU HAVE AN OPINION REGARDING THE SIGNIFICANCE OF THE HISTORICAL DATA REFLECTED IN THE TABLE ABOVE?

A. Overall, I believe that these results indicate that we have been successful in our annual budgets in projecting and managing our O&M expense.

Q. WHY IS THAT IMPORTANT?

A. This data demonstrates that the Company's budgeting and control processes I have described form a reasonable basis for purposes of the Company's forecasted test period O&M budget in this rate proceeding.

IV. FORECASTED TEST PERIOD O&M BUDGET

Q. WHAT IS THE FORECASTED TEST PERIOD USED IN THIS RATE APPLICATION?

A. The forecasted test period is July 1, 2007 through June 30, 2008.

Q. HOW WAS THE FORECASTED TEST PERIOD BUDGET DEVELOPED?

A. The basis for the forecasted test period is our FY2007 budget. Consistent with our normal annual budgeting timelines, this budget was prepared during the summer of 2006 and approved by the Board of Directors in September of 2006. This budget was prepared in the manner I described earlier. The forecasted test period includes three months of this approved budget (July – September 2007) and 9 months of a projection period (October 2007 – June 2008). I will describe the methodology used for the projection period in detail below. The FY2007 O&M budget and forecasted test period projection were converted into FERC account detail using the method described above.

Q. WHAT ARE THE COMPONENTS OF O&M FOR THE FORECASTED TEST PERIOD?

A. Consistent with the organizational changes discussed earlier in my testimony, the forecasted test period O&M is comprised of three parts: expenses incurred and booked directly in Kentucky, allocated expenses from the Kentucky/Mid-States Division General Office, and allocated expenses from SSU. I will describe the methodology used for the projection for each of the three components.

Q. WHAT COMPRISES THE BASE PERIOD LEVEL OF COST FILED IN THIS RATE APPLICATION?

A. The base period level of cost is April 1, 2006 through March 31, 2007. It is composed of six months of actual results up through September, 2006 and six months of our FY2007 budget that was prepared during the summer of 2006 and approved by the Board of Directors in September of 2006 (described above).

Q. WHAT IS THE DIRECT AND GENERAL OFFICE O&M FOR THE BASE PERIOD?

A. The aggregate amount of direct O&M for Kentucky and the Division's general office O&M allocated to Kentucky for the base period (hereinafter the "Base Period O&M") is $15,016,786.

Q. WHAT IS THE DIRECT AND GENERAL OFFICE O&M BUDGET FOR THE FORECASTED TEST PERIOD?

A. The aggregate amount of direct O&M for Kentucky and the Division's general office O&M allocated to Kentucky for the forecasted test period (the "Test Period O&M") is $15,875,934.

Q. WHY HAVE YOU COMBINED THE DIRECT KENTUCKY O&M AND DIVISION GENERAL OFFICE O&M FOR THE PURPOSE OF THIS COMPARISON?

A. Due to the organizational changes that became effective in the middle of the base period, combining the direct and allocated general office O&M provides the most meaningful "apples to apples" comparison for understanding the overall increase in expenses from the base to the test period. As explained earlier in my testimony, prior to October 1, 2006, the Kentucky rate jurisdiction operated as a one-state operating division of the Company. Therefore, division leadership and support people comprising that division's general office were embedded within the same rate jurisdiction as the operating personnel. Effective October 1, 2006 with the FY2007 budget and booking of actual costs, the Kentucky/Mid-States general office functions as a single general office rate division (with two primary physical locations) and allocates a portion of its costs to the Kentucky rate jurisdiction per the methodologies described in Mr. Cagle's testimony. The Kentucky/Mid-States Division's general office was budgeted separately in the FY2007 budget and is forecasted separately for the forecasted test period. The budgeting process and forecast methodologies, however, are identical for both components. Therefore, because the base period includes six months of legacy division structure and six months of new division structure, combining the two for the purposes of comparison is most meaningful.[3]

Q. WHAT IS THE TOTAL DOLLAR DIFFERENCE BETWEEN THE BASE PERIOD O&M AND TEST PERIOD O&M?

A. The total difference is $859,148 and reflects adjustments I have made for labor and benefits, rent, other O&M and bad debt.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR LABOR AND BENEFITS.

A. Labor expense is forecasted by projecting total labor expenditures and multiplying by one minus the forecasted labor capitalization rate. While there is always a normal level of position vacancy at any given point in time, we strive to fill open positions in a timely manner when and if filling the position is justified by current workload. The base period level of total labor expenditures represents a fully staffed level minus the normal level of vacancies. Therefore, employee levels are projected to remain relatively constant from the base period to the test period. Base pay increases go into effect each October 1 and have averaged 3.5% annually for the past several years. The increases that took effect October 1, 2006 are captured as part of the FY2007 budget. An adjustment was made as part of the forecast to account for an average wage increase of 3.5% to become effective October 1, 2007. Overall, total labor is projected to increase 2.9%, or $345,550, from the base period to the test period.

Labor capitalization rates are forecasted by analyzing annual historical patterns and considering known capital and expense initiatives that may alter anticipates rates. One minus the labor capitalization rate is multiplied by the total labor projection to arrive at the forecast for labor expense. The labor capitalization rate in the FY07 budget and test period averages 50% for the year. This is 2.5% lower than the labor capitalization rate in the base period. A higher than budgeted amount of capital work was done using in-house labor in the last quarter of FY06 causing the average base period capitalization rate to be higher than anticipated. The overall average capitalization rate for FY06 was 51.6%. Reducing the capitalization rate to 50% (consistent with the approved FY07 budget) and considering normal pay increases results in labor expense forecasted to increase $463,928 from the base period to the test period.

Benefits are projected as a fixed benefit load percentage of labor expense plus an

[3] The Base Period O&M does not include O&M allocated to the Division, and ultimately to Kentucky, by SSU.

amount for workers' comp insurance. The test period benefits expense of $2,570,636 is $160,924 higher than the base period.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO RENT.

A. Unlike other O&M categories that are likely to increase with normal inflation, our building rents are driven by leases already in place and can therefore be projected with a high level of accuracy. The rent portion of the O&M category "Rent, Utilities and Maintenance" was projected by reviewing actual lease amounts and contributes to this category being virtually flat from base to test period. The adjustment is a decrease of $1,698 from the base period.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO OTHER O&M.

A. For the purpose of this rate filing, O&M expense types other than labor, benefits, rent and bad debt are forecasted using a standard inflation factor. Using our FY2007 budget as a starting point, categories other than the ones listed above are inflated by 2.5% to arrive at the forecasted test period expense level. The 2.5% inflation factor is consistent with the Congressional Budget Office's forecast for inflation for 2007. Beginning in January, 2007, expenses for gas supply services have been moved from the Outside Services expense category in direct O&M to become a component of the allocated Shared Services expenses. This change is made in anticipation of an organizational change at the corporate level in which the department providing gas supply services will be moved from Atmos Energy Services to SSU, as more particularly described in the direct testimony of Mr. Gary Smith. The result of this change combined with the standard inflation factor for other categories is an $88,287 increase over the base period level of expenses for other O&M categories.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO BAD DEBT

A. Our goal is to keep bad debt no higher than 0.50% of residential, commercial and public authority revenues during any given year. We work vigorously to collect bad debts from customers each year to achieve this goal so as to reduce the impact of good-paying customers subsidizing poor-paying customers who drive up our expenses. To arrive at the bad debt projection of $1,007,867 we simply calculated 0.50% of residential, commercial and public authority revenues from the revenue projection in the direct

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SSU O&M is discussed later in my testimony.

testimony of Company witness Mr. Gary Smith. This projection is $147,709 higher than the base period due, in part, to the fact that we have used 0.45% as our accrual rate in Kentucky in recent years, including FY06 and in our FY07 budget. Our bad debt results from this past summer (which include bad debts primarily related to last winter) lead us to increase our projection from 0.45% to 0.50%. This level of 0.50% is the Atmos Energy standard and is the rate used by other states in the Kentucky/Mid-States Division. If our proposal to collect the gas cost portion of bad debts through the PGA is accepted, our bad debt projection would be modified to reflect 0.50% of residential, commercial and public authority margins. That projection for the test period would be $185,313.

Q. ARE ANY AFFILIATED OR NON-REGULATED OPERATIONS INCLUDED IN KENTUCKY'S O&M BUDGET?

A. Yes. As discussed in the direct testimony of Company witness Ms. Laurie Sherwood, the Division receives property insurance services from the Company's captive insurer, Blueflame Insurance Services, Ltd. ("Blueflame"). As more particularly discussed in the direct testimony of Mr. Cagle, Kentucky also receives an allocation of costs with respect to property insurance provided by Blueflame covering the property of the Division's general office plant as well as the SSU plant. The premiums cost to be charged directly to Kentucky by Blueflame during the base period is $323,241, and is $344,112 for the forecasted test period. A portion of these premiums are capitalized each month. Kentucky's allocated portion of the premium cost charged to the Division's general office is included as part of Other O&M for both the base and forecasted test periods.

Also included as part of the costs in this rate filing are costs from Blueflame allocated to Kentucky as part of the Shared Services costs for property insurance upon the SSU plant. Such costs are included in the Shared Services O&M amounts for the base period and forecasted test period.

Q. WHAT IS THE AMOUNT OF SHARED SERVICES O&M ALLOCATED TO KENTUCKY FOR THE BASE PERIOD?

A. $5,128,032.

Q. WHAT IS THE AMOUNT OF THE SHARED SERVICES O&M BUDGET

ALLOCATED TO KENTUCKY FOR THE FORECASTED TEST PERIOD?

A. $5,133,922

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE SHARED SERVICES BASE PERIOD AND FORECASTED TEST PERIOD AMOUNTS.

A. The difference is an increase of $5,890. As discussed in the direct testimony of Mr. Joel Bradshaw, the SSU budget is prepared in a fashion consistent to that of the Division. Once the SSU department heads complete, submit and get approval for their budgets, the appropriate level of expenses are allocated to the Kentucky rate jurisdiction per the methodologies described in Mr. Cagle's testimony.

Q. HOW DO YOU MONITOR SHARED SERVICES BILLINGS TO THE KENTUCKY/MID-STATES DIVISION?

A. Shared Services expense billings are reviewed as part of our monthly close process described earlier. It is my responsibility to contact Accounting in Dallas and obtain an explanation for any significant variances.

V. DEPRECIATION EXPENSE AND TAXES, OTHER THAN INCOME TAX

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE BASE PERIOD?

A. The amount of depreciation expense for the base period is $12,356,915.

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE FORECASTED TEST PERIOD?

A. The amount of depreciation expense for the forecasted test period is $12,878,199.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD AND FORECASTED TEST PERIOD DEPRECIATION AMOUNTS.

A. Depreciation rates for FY2007 and the forecasted test period are based on the results of the depreciation study for Kentucky recently conducted by Company witness Mr. Donald S. Roff. This study and the results thereof are more specifically discussed in Mr. Roff's direct testimony. The depreciation rates developed by Mr. Roff in his study for Kentucky have been applied to the applicable categories of plant, resulting in the total depreciation expense noted above.

The depreciation expense allocated to Kentucky by SSU is also based on a study recently conducted by Mr. Roff. This study and the results thereof are more specifically discussed in Mr. Roff's direct testimony. The depreciation rates for SSU by Mr. Roff in his study have been applied to the applicable categories of SSU plant, resulting in an allocation of SSU depreciation expense to Kentucky based upon the cost allocation methodology more fully explained in the direct testimony of Mr. Cagle.

Q. WHAT IS THE EXPENSE LEVEL FOR TAXES, OTHER THAN INCOME TAXES FOR THE BASE PERIOD?

A. $6,287,685.

Q. WHAT IS THE LEVEL OF TAXES, OTHER THAN INCOME TAXES FOR THE FORECASTED TEST PERIOD?

A. $5,255,646.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD AND FORECASTED TEST PERIOD BUDGETS.

A. The difference is a decrease of $1,032,039 for taxes, other than income taxes. There are two significant adjustments that contribute to this decrease. First, we booked the sum of $800,000 in September, 2006 (in the base period) to taxes, other than income taxes. This sum represents a non-recurring charge. A reserve was set up in this amount to cover a potential assessment which may result from a pending sales tax audit. The matter has yet to be resolved, although we anticipate the reserve to be sufficient. This one-time charge inflates the base period amount for taxes, other than income tax. Secondly, we have received an indication of our initial property value from the Kentucky Department of Revenue and our State Property Tax Bill for 2006. The property tax assessment indicated is $4,011,420. This is approximately $1,400,000 higher than was anticipated when the FY2006 and FY2007 budgets were developed. We accrue an amount each month for property taxes. The budgeted amounts were $216,804 per month during FY2006 and $219,285 per month for FY2007. For the purposes of this rate filing, we have assumed that a "catch-up" entry will be made in December, 2006 to cover the assessment and, beginning in January, 2007, we will begin accruing at a monthly rate of $334,285. That amount will grow by 3% beginning in November, 2007, when we expect to receive our initial 2007 assessment. Due to the fact that the catch-up entry is made during the base period, it contributes to base period taxes being higher than those in the forecasted test period.

VI. CONCLUSION

Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD O&M BUDGET YOU HAVE PRESENTED IS THE MOST REASONABLE ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS PROCEEDING?

A. Yes. It is the best estimate we have of the Kentucky jurisdiction's future operating and maintenance expenses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Robert R. Cook, Jr., being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

STATE OF Kentucky
COUNTY OF Daviess

SUBSCRIBED AND SWORN to before me by Robert R. Cook, Jr. on this the 18th day of December, 2006.

Notary Public
My Commission Expires: 11/15/2007

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORATION	)	

TESTIMONY OF ROBERT R. COOK JR.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Robert R. Cook Jr. I am Vice President Technical Services of the Kentucky/MidStates Division of Atmos Energy Corporation ("Atmos Energy" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Civil Engineering from Murray State University in 1990.

I have been employed in the utility industry for 16 years, predominantly in the natural gas transmission field. I have been employed by Atmos Energy Corporation for approximately three (3) years. My previous employer was Williams Gas Pipeline Company – Texas Gas.

During my time at Williams Gas Pipeline Company, I worked in design and construction as a project engineer in Kentucky from 1990 until 1999. I then worked as a project manager in the engineering department overseeing pipeline and compression projects in Kentucky until 2000. From 2000 until 2003, I worked in Houston, Texas as manager of construction/mapping for Williams Gas Pipeline Company.

In 2004, I returned to Kentucky to join Atmos Energy as Vice President of Technical Services for its Kentucky Division. Effective October 1, 2006, I assumed the responsibility as Vice President of Technical Services for the consolidated Kentucky/Mid-States Division.[1]

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE VICE PRESIDENT OF TECHNICAL SERVICES?

A. I have overall responsibility for decision-making related to technical operations. This includes engineering and system design, safety, compliance, procurement, environmental, measurement, communications, technological infrastructure, and storage operations. I also sponsor Atmos' safety committee and am a member of the Atmos' Utility Operations Council, which sets the Company's standard practices and procedures for construction, maintenance and service. In addition, I am responsible for developing the Division's (including Kentucky) annual capital budget and monitoring capital budgetary compliance. In this regard, it is my role to ensure that Kentucky's investment in new plant and equipment is targeted towards meeting the important goals of public safety, system reliability and efficiency.

Q. HAVE YOUR EVER SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS AND, IF SO, WHICH?

A. I am sponsoring the following filing requirements:

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[1] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated and are now, in effect, one division – the Kentucky/Mid-States Division. "Division" as used in my testimony means the Company's Kentucky/Mid-States Division. "Kentucky" when used in my testimony, unless indicated otherwise, refers exclusively to the Company's operations in Kentucky.

FR 10(9)(b)	Kentucky's most recent capital construction budget containing four fiscal years of construction expenditures.
FR 10(9)(c)	A complete description of all factors used in preparing Kentucky's capital construction budget.
FR 10(9)(f)	Detailed information for each major construction project constituting more than five percent (5%) of the annual construction budget within the three (3) year forecast.
FR 10(9)(g)	Detailed information for the aggregate of construction projects constituting less than five percent (5%) of the annual construction budget within the three (3) year forecast.
FR 10(9)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with this application.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the capital expense ("Capex") budgeting process used by the Company, describe the control and monitoring of Capex variances, and describe the Capex budget by major plant category, including the portion of the Kentucky/Mid-States Division and Shared Services capital expenditures allocated to Kentucky. I will also sponsor the service charge studies supporting the proposed service charges.

<u>II. CAPITAL BUDGETING PROCESS</u>

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S CAPITAL BUDGETING PROCESS?

A. The objectives of the Company's capital budgeting process are to:

(1) Formalize the process of identifying construction needs and prioritizing capital expenditures;

(2) Assess the economic feasibility of individual construction projects;

(3) Determine overall capital requirements for the planning periods;

(4) Reassess long term system maintenance requirements annually; and

(5) Review past construction projects and work practices, and apply procedural improvements as appropriate.

Q. PLEASE DESCRIBE THE PLANNING AND BUDGET PROCESS FOR THE COMPANY'S CAPITAL CONSTRUCTION PROGRAM?

A. The Company plans its capital expenditures over five fiscal years, with a focused emphasis on the first year of that five-year period. We normally begin this process during our third fiscal quarter (April-May) of each year, some 4 to 5 months prior to the beginning of the next fiscal year. The process is initiated within the Division by a request from my office for a "bottom-up" submission of projects from our town supervisors and operations managers in Kentucky. All proposed projects, vehicles, and equipment must be identified at a high level by need and cost, and all budgets are prepared based upon meeting the five objectives described above. The proposed projects, vehicles, and equipment are reviewed by Kentucky/MidStates Division's, regional vice presidents of operations for collaborative agreements between the regional vice presidents, operations managers, and myself.

After review, additional information is requested for projects that are determined to be the most eligible for funding and more detailed documentation is requested from the operations and technical services managers on those particular projects. The process is largely complete by late June when projects are entered into the Atmos Energy capital budget system (PlanIt), although finalization of capital expenditures is not completed until late July. During this time, the agreed-to projects have been further substantiated to ensure they meet the appropriate financial criteria and the stated objectives.

The final proposed budget must be reviewed by the Division's senior management, including the Division President. Additional reviews are performed by corporate executive operations management and their staff. High level reviews of the division budgets are also performed by the Company's senior executives who are presiding members of the Company's Management Committee. The Capex budget for Kentucky is not officially approved until it, as part of the Company's total Capex budget, is presented to the Company's Board of Directors in September of each year. Upon this approval, all approved projects are transferred into the Atmos Energy capital tracking system (POWERPLANT) and are ready for appropriation.

Q. HOW DOES ATMOS PRIORITIZE ITS CAPITAL EXPENDITURES?

A. Our priorities for capital expenditure, listed in order of importance, are:

1. Public Safety
2. System Capacity and Reliability
3. Customer Growth
4. Facilities Maintenance
5. Public Works, and
6. Support of Long Term Technological Programs.

Typically, the funds for customer growth constitute about 33% of our annual capital expenditures. The other components comprising our non-growth capital expenditures, including our technology investments, make up the balance of our spending.

Q. WHAT FINANCIAL CRITERIA ARE THE MOST SIGNIFICANT IN APPROVING A PROJECT DURING THE CAPITAL BUDGETING PROCESS?

A. We begin work with an overall capital spending goal which we try to work within, although variations are permitted if justified. We also use key investment criteria to evaluate projects. Any expenditure above targeted levels must be justified. Individual projects, and our construction program as a whole, are assessed on the basis of their return on investment, return on equity, cost of capital, cash flow, new business forecasts, and various capital overheads such as labor, benefits, and inflation.

Q. MUST ALL PROJECTS MEET THE SAME FINANCIAL CRITERIA?

A. No. We separate projects into growth and non-growth capital expenditures. Growth projects are revenue-producing investments for which we can identify a stream of revenues, cash flow, return, payback and other standard investment criteria. Non-growth capital expenditures involve system integrity, equipment, structures, pipeline integrity, system maintenance and reliability projects which are evaluated on a cost/benefit basis. We endeavor to keep our annual non-growth capital expenditures below the level of depreciation. Since these expenditures do not have an associated stream of revenues, our goal is to fund these expenditures through internal financial cash flow. Obviously, there are certain non-growth expenditures which do not impact public safety that can be scheduled into our five-year investment program to ensure that we properly maintain our system while still operating within overall cash flow constraints. Expenditures which impact public safety have always had and will continue to have the highest priority. To help manage and prioritize our System Integrity pipeline replacements projects, we use our Atmos Risk Management Model (ARMM). ARMM is a computer software that was developed to identify and prioritize pipeline replacements, primarily our bare steel pipelines. We take our obligation to build and operate a safe and reliable gas system very seriously. Finally, there are also a number of projects we must fund over which we have little control as to timing, such as public works projects and highway relocations.

Q. HOW CAN THE COMPANY JUSTIFY ADDITIONAL EXPENDITURES BEYOND ITS REGULAR CAPITAL BUDGET PROJECTIONS?

A. Kentucky/Mid-States can secure additional funding through Atmos Energy if we can demonstrate that we have potential investments which compare more favorably to competing expenditures in other Atmos business units and are, therefore, more worthy of immediate funding from a purely financial standpoint.

Expenditures that impact public safety or compliance projects have the highest priority and are considered mandatory capital projects.

III. CONTROL & MONITORING OF CAPITAL EXPENDITURES

Q. WHAT ARE THE GOALS OF THE COMPANY'S PROCESS OF CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES?

A. Variances from budgeted amounts are inherent in the process of making capital expenditures. Our variance monitoring process exists to institute financial quality control by formalizing the analysis of variances by responsibility center in a process that identifies year-to-date spending variances by project. These reports are received and reviewed every month at the business unit level and on a quarterly basis at the corporate level. The goal is to keep all levels of management informed of spending by category or project relative to budgeted levels and to ensure that corrective action is initiated on a timely basis. This supports decision-making related to the cost and appropriate management of current and future capital projects.

Q. PLEASE DESCRIBE THE COMPANY'S PROCESS FOR CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES.

A. The Company's capital budgeting system maintains projects in two broad categories – Blanket Functionals and Specific Projects. The Blanket Functionals include total capital authorizations of a similar type such as new services, leak repair, short main replacements, small integrity/reliability projects, etc. Specific projects are uniquely identified such as a specific highway relocation project, replacement of work equipment, or some larger significant integrity/reliability project.

Once a project has been entered in the capital budget system an appropriation Purpose and Necessity (P&N) may be submitted for authorization. Projects are then monitored to ensure they stay within budgeted levels. If during the course of a project, field management identifies that the costs of the project will exceed approved amounts, a request for supplemental funding may be submitted. All expenditures above authorized appropriation, as well as expenditures for unbudgeted projects or variances on budgeted and approved projects, must be approved at the appropriate levels within the Company.

Each month, various project variance reports are published. Each budget center manager is responsible and held accountable for managing their overall approved capital budget.

Q. DISCUSS THE VARIANCES INCURRED DURING THE MOST RECENT FISCAL YEARS' CAPITAL BUDGETING PROGRAM.

A. In fiscal year 2006, the Company's actual capital expenditures in Kentucky were $16,645,007 resulting in a variance of +17.34% over the 2006 budget. As we progress into summer, the pace of our construction and the corresponding capital expenditures normally increase. Further, in fiscal year 2006, the Kentucky highway non-reimbursement relocation project's schedule was revised and work scheduled for 2007 was instead performed in 2006. This project along with other public improvement projects was completed during the 2006 budget year resulting in an increase of $349,032. In addition, system improvement/system integrity projects resulted in an increase of $1,220,220 over budget. This overage resulted from replacing some of our 1930's Hopkinsville 10-inch pipeline and other system integrity replacement projects. Further, our structures budget category was $289,718 over budget. This resulted from the purchase of a piece of land and the removal of the existing building located adjacent to our Owensboro, Kentucky service center.

Q. WHAT HAS THE COMPANY'S RECENT EXPERIENCE BEEN IN TERMS OF VARIANCES BETWEEN BUDGETED DOLLARS AND ACTUAL DOLLARS SPENT?

A. The following table shows Kentucky's historical capital expenditures, including overheads, compared to budget:

Fiscal Year	Actual Dollars	Budgeted Dollars	Over/(Under) Budget, $'s	Variance (%)
2006	16,645,007	14,185,245	2,495,762	17.3
2005	17,525,670	14,571,690	2,953,980	20.3
2004	20,902,147	18,550,753	2,351,394	12.7
2003	18,213,227	18,702,001	(488,774)	(2.62)
2002	18,188,126	15,326,768	2,861,358	18.6

As this table indicates, variances in capital budgeting do occur. For example, in 2005, we spent $1,101,204 over budget in system improvement/system integrity projects. This overage resulted from replacing some of our bare steel pipe and overhauling one of our storage reciprocating engine/compressors.

IV. TEST PERIOD CAPITAL BUDGET

Q. WHAT IS THE FORECASTED TEST PERIOD USED IN THIS RATE APPLICATION?

A. The forecasted test period is July 1, 2007 through June 30, 2008. This represents 3 months of Kentucky's fiscal year 2007 (FY2007) and 9 months of Kentucky's fiscal year 2008 (FY2008).

Q. WHAT IS KENTUCKY'S FORECASTED TEST PERIOD CAPITAL BUDGET?

A. Kentucky's forecasted test period's capital budget is $20.6 million. Kentucky's capital budget is comprised of three components – the direct capital spending for Kentucky for the forecasted test period, the amount allocated to Kentucky resulting from capital spending by the Kentucky/Mid-States Division's general office and the amount allocated to Kentucky resulting from capital spending by the Company's Shared Services (SSU) during the forecasted test period. The budgeting process for SSU Capex is described in the direct testimony of Company witness Mr. Joel Bradshaw and the amounts which are projected to be closed to plant and comprising additions to SSU ratebase are sponsored by Company witness Mr. Thomas Petersen. The methodology for allocating SSU and the Division general office ratebase amounts to Kentucky is described in the testimony of Company witness James Cagle.

Q. HOW WAS KENTUCKY'S DIRECT CAPITAL BUDGET FOR THE FORECAST PERIOD DEVELOPED?

A. We relied upon the FY2007 capital budget as a baseline for projecting detailed FY2007 through FY2008 capital expenditures for purposes of the test period in this rate application. I also prepared fiscal year capital budget estimates for FY2009.

Q. WHAT IS KENTUCKY'S FY2007 DIRECT CAPITAL BUDGET?

A. The approved FY2007 direct capital budget for Kentucky is $17.3 million.

Q. WHAT IS KENTUCKY'S FY2008 DIRECT CAPITAL BUDGET AS ESTIMATED IN THE FIVE YEAR PLANNING PROCESS?

A. Kentucky's FY2008 direct capital budget is estimated at $18.1 million.

Q. HOW DID YOU ADJUST KENTUCKY'S FY2008 DIRECT CAPITAL BUDGET IN ORDER TO PREPARE THE FORECASTED TEST PERIOD CAPITAL BUDGET?

A. The actual estimated cost of budgeted projects planned for FY2007, before the application of overheads, was used as a baseline. That amount was approximately $11.2 million. Three factors were evaluated and used to adjust the baseline. These adjustments were necessary in order to reflect the most current information available which would impact our future level of capital spending and thus ensure that the direct capital budget is accurate. These three factors are:

1. Changes related to system integrity and system improvement projects;
2. Cost increases in materials and labor tied to inflation; and
3. An application of overheads attributable to capital projects.

Q. PLEASE DISCUSS EACH OF THESE FACTORS.

A. The change in system integrity and system improvements reflects an anticipated increase in capital spending above FY2007 levels for leak repairs, bare steel replacement, cathodic protection, and system improvements for increased system capacity and reliability. We expect to sustain this level of work in FY2008 and

FY2009 with an anticipated increase in cost of material and labor. No major changes in overhead rates are anticipated.

Q. HOW WAS THE DIVISION'S GENERAL OFFICE CAPITAL BUDGET DEVELOPED?

A. The capital budget for the Kentucky/Mid-States Division general office was developed in conjunction with Kentucky's capital budget as well as the capital budgets for all other rate divisions within the Division as part of the Division's total capital budget. The budgeting processes I have described herein applied to all rate division capital budgets which roll up into the Division's total capital budget, including Kentucky and the Division general office.

Q. WHAT IS THE PORTION OF THE DIVISION'S FY2007 CAPITAL BUDGET ALLOCATED TO KENTUCKY?

A. The portion of the approved FY2007 Division's general office capital budget allocated to Kentucky is $51,000.

Q. WHAT ABOUT SUBSEQUENT FISCAL YEARS?

A. Those forecasted amounts are $54,000 for FY2008 and $57,000 for FY2009.

Q. HOW WAS THE SHARED SERVICES TEST PERIOD CAPITAL BUDGET DEVELOPED?

A. The development of the Shared Service capital budget for the forecasted test period is described in Mr. Bradshaw's direct testimony.

Q. WHAT IS THE SHARED SERVICES FY2007 CAPITAL BUDGET ATTRIBUTABLE TO KENTUCKY?

A. The portion of the approved FY2007 Shared Services capital budget allocated to Kentucky is $0.8 million.

Q. WHAT ABOUT SUBSEQUENT FISCAL YEARS?

A. Those forecasted amounts are $0.9 million for FY2008 and $0.9 million for FY2009.

Q. PLEASE DISCUSS KENTUCKY'S OVERALL FORECASTED CONSTRUCTION PROGRAM.

A. Kentucky's capital budget was developed by the following major categories:

1. Equipment

2. Growth
3. Information Technology (IT)
4. Pipeline Integrity
5. Public Improvements
6. Structures
7. System Improvements
8. System Integrity
9. Vehicles

These categories are reflected in FR 10(9)(b).

Q. WHAT KEY NEEDS ARE MET THROUGH THIS PARTICULAR BUDGET?

A. System improvement, pipeline integrity, and system integrity investments focus on customer safety and system reliability, are our highest priorities for capital budgeting. The next priority is public improvements and state and local public works projects such as highway relocations. The next priority is customer growth. Atmos Energy continues to build good working relationships with developers, economic development boards, and growing communities to meet the needs of the customer and to accommodate customer growth on its system. Next, a modern fleet of vehicles and equipment (backhoes, safety equipment, ditchers, first responder equipment, air compressors, welding machines, etc.) allows us to maintain our system and continue to provide a reliable level of service to our customers. To enhance the level of customer service provided in the field, we also continue to make investments in new technology. Technology is a strategic investment that will enable us to continue improving our business processes, hold down operating costs, and meet the changing expectations of our customers.

V. SERVICE CHARGE STUDIES

Q. HAVE YOU OR PERSONS UNDER YOUR SUPERVISION CONDUCTED SERVICE CHARGE STUDIES RELATED TO KENTUCKY'S SERVICE CHARGES?

A. Yes. Those studies are attached to my testimony as Exhibit RRC-1.

Q. WHAT IS THE PURPOSE OF THESE STUDIES?

A. The purpose is to determine the underlying costs associated with performing the non-recurring or special services offered to our customers. This was done to support, through analysis, rates consistent with the cost of these special services by comparing the Company's current rates in Kentucky with the actual cost to perform these services.

Q. WHICH OF THE SERVICE CHARGES IS THE FOCUS OF THE ANALYSIS?

A. The cost analysis focuses on the charges for meter set, turn-on, meter reads, reconnect delinquent service and seasonal turn-ons.

Q. WHAT COST STUDIES WERE PERFORMED?

A. There were a number of cost analyses included in the performance of these studies. We performed a salary load computation for employees performing and supervising this type of work. We also obtained actual costs of customer inquiries for Kentucky and calculated an average cost per call for FY 2006. Additionally, we obtained the annual service order activity which provided average completion and travel times for each service order type included in this cost study. All the foregoing were needed to develop a per service order cost assignment. Finally, we conducted a survey of banks to determine an appropriate charge for returned checks.

Q. BRIEFLY DESCRIBE HOW EACH COST ANALYSIS WAS PERFORMED.

A. The cost analyses were performed in the following manner:

1. Salary Load Computation. We began by developing a salary cost per minute of the service technician, administrative support, and supervision for the time to perform each order. The mid-point of current salary ranges for employees performing these tasks were used and the actual benefit and

payroll load factors were then added to the calculation. Overtime calculations were only applied to the labor costs of Senior Service Technicians at the rate of 1.5.

2. Trip Mileage Analysis. We determined the average travel time and distance between orders, and by applying the payroll loadings assigned to the service technician; we arrived at a travel cost per order.

3. Customer Handling Time Analysis. We documented the total FY 2006 costs and number of customer calls from our Kentucky customers to our Customer Support Center and divided to get an average cost per call.

4. Service Order Activity Analysis. We compiled and reviewed annual service order activity and completion times required to initiate and process all orders. By determining the actual time to complete each order we were able to calculate the cost to perform each order by Atmos service order abbreviations.

Q. PLEASE DESCRIBE THE RESULTS OF THE COST ANALYSES.

A. The results of the Special Service Charge Analysis are displayed in Exhibit RRC-1 and summarized in the following table:

Description	Total Cost To Perform	Current Rates (Business Hours)
Meter Sets	$33.14	$28.00
Turn On	$22.02	$20.00
Turn On from Non Pay	$20.23	$34.00
Turn Off from Non Pay	$17.90	
Turn on from Seasonal off	$20.55	$65.00
Read and Run	$11.90	$12.00

As indicated in the above table, we are presently under recovering for all service orders except for our read and run service orders and turn-on(s) from a seasonal off(s) which were intentionally set at levels to discourage heat-only customers from turning off every spring.

Q. WHAT WAS THE RESULT OF THE SURVEY OF BANKS RELATIVE TO RETURNED CHECKS?

A. We surveyed eight (8) local banks and identified the average returned check charge being applied. The premise of this survey is that we incur a similar administrative cost when handling checks returned for non-sufficient funds. Our current charge of $23.00 is slightly below that average.

Q. BASED ON YOUR ANALYSIS, WHAT CONCLUSIONS HAVE YOU REACHED REGARDING THE RELATIVE COSTS OF THESE SERVICES?

A. This study indicates that some services have similar cost components but may differ by factors such as the time required to perform the services or the number of times a premise must be visited. For example, the cost to initiate service (turn-on) for a new customer that has an existing meter is similar to the cost for re-establishing service for non-pay except that an additional premises visit is required for reconnecting delinquent service. This study makes it clear that some restructuring of special service charges is necessary if Company is to fully recover its special services costs directly from those customers that cause or benefit from the costs being incurred. Mr. Gary Smith will present the proposed charges in his testimony.

VI. OTHER STUDIES

Q. HAVE YOU OR SOMEONE UNDER YOUR SUPERVISION CONDUCTED ANY OTHER STUDIES PERTAINING TO CHARGES IN KENTUCKY?

A. Yes. The Technical Services Department reviewed the EFM charges contained in our existing tariff. Costs have declined significantly for some installations and increased for another. We have consulted with Mr. Gary Smith about the appropriate rates for EFM.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT RRC-1

Exhibit RRC 1

Atmos Energy- Kentucky
Special Service Charge Analysis

Line No.	Description	Work Codes	Total Orders Worked	# Orders Billed During Reg. Hours	# Orders Billed After Hours	Average Time To Complete (Minutes)	Sr. Service Technician Salary & Load Per Minute 0.45	Office Salary & Load Per Minute 0.02	Supervision Salary & Load Per Minute 0.09	Total Salary Load Per Order	Travel Cost Between Orders	Service Cost Per Order	CSC Preparation and Processing of Order	Total Cost To Perform	Current Rates (Business Hours)	Current Revenue	Proposed Rates (Business Hours)	Proposed Rates (After Hours) [1]	Proposed Revenue	Increase In Revenue
	(1)	(2)	(5)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
1	Meter Sets	MSET/NEWC	5,354	3,864	1	46	$20.65		$4.02	$24.67	$4.56	$29.23	$3.91	**$33.14**	$28.00	$108,227	$34.00	$44.00	$131,420	$23,193
2	Turn On	TOSI/RCUS	11,751	11,025	3	25	$11.34		$2.21	$13.55	$4.56	$18.11	$3.91	**$22.02**	$20.00	$220,575	$23.00	$28.00	$253,659	$33,084
3a	Turn On from Non Pay	RDEL	7,104	6,463	19	22	$9.84		$1.92	$11.76	$4.56	$16.32	$3.91	**$20.23**	$34.00	$220,502	$39.00	$47.00	$252,950	$32,448
3b	Turn Off from Non Pay	DELQ	13,636			17	$7.58	$0.38	$1.48	$9.43	$4.56	$13.99	$3.91	**$17.90**						
4	Turn on from Seasonal off	RSEA	238	214	0	25	$11.11		$0.98	$12.08	$4.56	$16.65	$3.91	**$20.55**	$65.00	$13,910	$65.00	$73.00	$13,910	$0
5	Read and Run	RRUN	19,556	18,282	0	7	$3.16		$0.28	$3.43	$4.56	$8.00	$3.91	**$11.90**	$12.00	$219,384	$12.00	$14.00	$219,384	$0
6	Return Check Charges		3,593												$23.00	$82,639	$ 25.00		$89,825	$7,186
7	Totals															$865,237			$961,148	$95,911

[1] The after hours rate is calculated using 1.5 times column (5), Service Technician Salary & Load, plus the remaining charges.

Atmos Energy Kentucky Division
Computation of Senior Service Tech Costs per Minute
KY Field

Line No.	Description	All Field Service Personnel
	(1)	(2)
1	FY 2007 Mid-Point of Senior Service Tech pay grade 2	17.84
2	Times Benefits and Payroll Tax Loading Factor	1.52
3	Average Salary per Employee w\Benefits	27.12
4	Divided by 60 Minutes per Hour	60
5	Employee Cost per Minute	0.45

Atmos Energy Kentucky Division
Computation of Office Assistant (OA) Costs per Minute
KY Office

Line No.	Description	All Field Office Assistants
	(1)	(2)
1	FY 2007 Mid-Point of Office Assistants (OA) pay grade 2	17.84
2	Times Benefits and Payroll Tax Loading Factor	1.52
3	Average Salary per Employee w\Benefits	27.12
4	Divided by 60 Minutes per Hour	60
5	Employee Cost per Minute	0.45
6	Times .05 of OA's Time on DELQ or DTAG Service Orders	0.02

Atmos Energy Kentucky Division
Computation of Operations Supervisor Costs per Minute
KY Office

Line No.	Description	All Field Service Personnel
	(1)	(2)
1	FY 2007 Mid-Point of Operations Supervisor pay grade 5	34.74
2	Times Benefits and Payroll Tax Loading Factor	1.52
3	Average Salary per Employee w\Benefits	52.81
4	Divided by 60 Minutes per Hour	60
5	Employee Cost per Minute	0.88
6	Times .10 of Supervisors Time spent on SOs	0.09

Exhibit RRC 1
Page 5 of 10

Atmos Energy Kentucky Division
Travel & Completion Times

Line #	BU	State	S/O	Total Orders	Avg. Travel time (mins)	Avg. Worked time (mins)
	(1)	(2)	(3)	(4)	(5)	(6)
12	50	KY	**MSET Total**	3559	9.4	45.7
24	50	KY	**NEWC Total**	1795	10.5	45.7
36	50	KY	**RCUS Total**	359	9.6	22.8
48	50	KY	**RDEL Total**	7104	8.1	21.8
60	50	KY	**RRUN Total**	19556	8.2	7.0
72	50	KY	**RSEA Total**	238	9.1	24.6
84	50	KY	**TOSI Total**	11392	7.9	27.4
96	50	KY	**DELQ Total**	13636	5.0	16.8
97			**Grand Total**	**57,639**	**7.0**	**23.5**

98

99 Source: Advantex reporting for October 1, 2005 - September 30, 2006.

Atmos Energy Kentucky Division
Travel Cost
Between Orders

Line No.	Description (1)	All Field Service Personnel (2)
1	Estimated Average Speed (Miles per Hour)	25.00
2	Minutes per Mile[1]	2.40
3	Total Number of Miles Driven for these SOs FY 2006	167,531.54
4	Total Number of Service Orders Worked	57,639
5	Miles Between Orders	2.91
6	Minutes Between Orders	6.98
7	Loaded Salary per Minute	0.45
8	Employee Travel Cost per Order	3.15
9	Vehicle Cost per Mile[2]	0.49
10	Vehicle Cost per Order	1.41
11	Total Cost to Arrive	4.56

[1] Minutes Divided by 25 Mph
[2] IRS Rate for Expenses of Operating a Vehicle as of 01/01/2007

Atmos Energy - Kentucky Division
Returned Check Charge
Survey of Banks - November 27, 2006

Line No.	Bank (1)	CHARGE (2)
1	Chase Bank	$ 32.00
2	Bank of Ohio County	$ 20.00
3	Independence Bank	$ 30.00
4	Fifth Third Bank	$ 33.00
5	First Security Bank of Owensboro	$ 30.00
6	National City Bank	$ 10.00
7	Branch Banking &Trust (BB&T)	$ 5.00
8	Old National Bank	$ 33.00
9	**Average Return Check Charge**	**$ 24.13**

Atmos Energy - Kentucky Division
Cost Per Call FY 2006
Customer Support Center

Line No.		
1	Total KY Calls (including IVR handled calls)[1]	453,494
2	Total Cost[2]	$ 1,771,371
3	Cost Per Call	$3.91

[1]Source: Discoverer CMR Reports
[2]Source: Avaya CMS Reports

Atmos Energy Kentucky Division
FY 2006 Service Orders by Month & Billings
KY Office

Line No.	MONTH (1)	SO Type (2)	Total Orders (3)	Orders Not Billed (4)	Billed Charges (5)	Unbilled (6)	FY SO Totals (7)
1	Oct-05	MSET	545	49	$13,894	$1,372	
2	Nov-05	MSET	585	119	$13,054	$3,332	
3	Dec-05	MSET	506	90	$11,648	$2,520	
4	Jan-06	MSET	206	23	$5,124	$644	
5	Feb-06	MSET	300	37	$7,382	$1,036	
6	Mar-06	MSET	278	32	$6,894	$896	
7	Apr-06	MSET	160	14	$4,095	$392	
8	May-06	MSET	182	20	$4,548	$560	
9	Jun-06	MSET	167	18	$4,178	$504	
10	Jul-06	MSET	155	14	$3,948	$392	
11	Aug-06	MSET	198	20	$4,984	$560	
12	Sep-06	MSET	277	27	$7,000	$756	
13	Oct-05	NEWC	310	190	$3,360	$5,320	
14	Nov-05	NEWC	305	177	$3,584	$4,956	
15	Dec-05	NEWC	237	132	$2,924	$3,696	
16	Jan-06	NEWC	135	83	$1,456	$2,324	
17	Feb-06	NEWC	131	64	$1,876	$1,792	
18	Mar-06	NEWC	118	62	$1,568	$1,736	
19	Apr-06	NEWC	35	29	$168	$812	
20	May-06	NEWC	77	39	$1,064	$1,092	
21	Jun-06	NEWC	124	63	$1,708	$1,764	
22	Jul-06	NEWC	77	41	$1,008	$1,148	
23	Aug-06	NEWC	124	70	$1,512	$1,960	
24	Sep-06	NEWC	122	76	$1,288	$2,128	5,354
25	Oct-05	RDEL	770	29	$25,206	$986	
26	Nov-05	RDEL	769	103	$22,670	$3,502	
27	Dec-05	RDEL	402	50	$11,992	$1,700	
28	Jan-06	RDEL	538	77	$15,704	$2,618	
29	Feb-06	RDEL	618	70	$18,624	$2,380	
30	Mar-06	RDEL	890	99	$26,912	$3,366	
31	Apr-06	RDEL	670	54	$20,950	$1,836	
32	May-06	RDEL	907	37	$29,580	$1,258	
33	Jun-06	RDEL	507	21	$16,524	$714	
34	Jul-06	RDEL	354	13	$11,594	$442	
35	Aug-06	RDEL	262	10	$8,574	$340	
36	Sep-06	RDEL	417	59	$12,184	$2,006	7104
37	Oct-05	RRUN	1,675	137	$18,304	$1,644	
38	Nov-05	RRUN	1,819	111	$20,509	$1,332	
39	Dec-05	RRUN	2,009	162	$22,154	$1,944	
40	Jan-06	RRUN	1,982	127	$22,260	$1,524	
41	Feb-06	RRUN	1,918	91	$21,924	$1,092	
42	Mar-06	RRUN	1,757	110	$19,612	$1,320	
43	Apr-06	RRUN	1,204	68	$13,632	$816	
44	May-06	RRUN	1,426	111	$15,780	$1,332	
45	Jun-06	RRUN	1,511	94	$17,004	$1,128	
46	Jul-06	RRUN	1,297	81	$14,592	$972	
47	Aug-06	RRUN	1,556	86	$17,640	$1,032	
48	Sep-06	RRUN	1,402	96	$15,672	$1,152	19,556

Atmos Energy Kentucky Division
FY 2006 Service Orders by Month & Billings
KY Office

Line No.	MONTH	SO Type	Total Orders	Orders Not Billed	Billed Charges	Unbilled	FY SO Totals
49	Oct-05	RSEA	97	5	$5,935	$325	
50	Nov-05	RSEA	66	7	$3,835	$455	
51	Dec-05	RSEA	20	0	$1,300	$0	
52	Jan-06	RSEA	2	0	$130	$0	
53	Feb-06	RSEA	1	0	$65	$0	
54	Mar-06	RSEA	2	0	$130	$0	
55	Apr-06	RSEA	2	0	$130	$0	
56	May-06	RSEA	2	0	$130	$0	
57	Jun-06	RSEA	2	0	$130	$0	
58	Jul-06	RSEA	3	0	$195	$0	
59	Aug-06	RSEA	8	0	$520	$0	
60	Sep-06	RSEA	33	12	$1,365	$780	238
61	Oct-05	RCUS	72	38	$680	$760	
62	Nov-05	RCUS	49	35	$280	$700	
63	Dec-05	RCUS	28	12	$320	$240	
64	Jan-06	RCUS	23	14	$180	$280	
65	Feb-06	RCUS	11	6	$100	$120	
66	Mar-06	RCUS	33	21	$240	$420	
67	Apr-06	RCUS	25	11	$285	$220	
68	May-06	RCUS	18	12	$120	$240	
69	Jun-06	RCUS	14	9	$100	$180	
70	Jul-06	RCUS	15	7	$160	$140	
71	Aug-06	RCUS	31	22	$180	$440	
72	Sep-06	RCUS	39	26	$260	$520	
73	Oct-05	TOSI	1,761	40	$34,464	$800	
74	Nov-05	TOSI	2,043	109	$38,741	$2,180	
75	Dec-05	TOSI	1,299	80	$24,417	$1,600	
76	Jan-06	TOSI	788	45	$14,864	$900	
77	Feb-06	TOSI	837	52	$15,700	$1,040	
78	Mar-06	TOSI	560	43	$10,365	$860	
79	Apr-06	TOSI	437	23	$8,285	$460	
80	May-06	TOSI	628	20	$12,194	$400	
81	Jun-06	TOSI	631	18	$12,260	$360	
82	Jul-06	TOSI	635	25	$12,200	$500	
83	Aug-06	TOSI	785	25	$15,200	$500	
84	Sep-06	TOSI	989	30	$19,172	$600	11,751
85	**Totals**		44,003	4,132	$782,494	$94,148	44,003
86	**Total Billed and Unbilled Charges**				$876,642		
87							
88	Source: Advantex reporting for October 1, 2005 - September 30, 2006.						

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Joel R. Bradshaw, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

Joel R. Bradshaw

STATE OF Texas
COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by Joel R. Bradshaw on this the 18th day of December, 2006.

Ethel Z. Taylor
Notary Public
My Commission Expires: August 13, 2010

NOTARY PUBLIC STATE OF TEXAS
ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORTION	)	

TESTIMONY OF JOEL R. BRADSHAW

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joel R. Bradshaw. My business address is 5430 LBJ Freeway, Suite 400, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Business Planning and Analysis for Atmos Energy Corporation (hereinafter "Atmos" or the "Company").

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am primarily responsible for directing, planning, organizing, coordinating and overseeing the Company's budgetary and financial planning functions to facilitate management decision-making activities. In that role, I have management responsibility for the development, recommendation, implementation and monitoring of policies and procedures for the Company's budgeting process, including the annual budget and long-range financial forecasts and plans, quarterly revised financial forecasts and monthly, quarterly and year-to-date variance analysis. These functions are directly facilitated under my supervision by the departmental planning analysts who report to me. Until November of 2005, Mr. Greg Waller, another Company witness in this case, was an analyst within my department who reported to me and who is very familiar with and knowledgeable of the Company's budgetary and financial planning processes, including the control mechanisms in place, such as variance monitoring and reporting, as part of those processes. Mr. Waller is now the Vice President of Finance for the Kentucky/Mid-States Division of the Company.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelors Degree in Business Administration from the University of Texas at Austin with a major in accounting. I have worked in the business planning discipline for the past twelve years of my career. I have worked in the Company's Shared Services group for Atmos Energy for almost four years.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. I am a certified public accountant in the state of Texas.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION OR OTHER REGULATORY ENTITIES?

A. I have not testified before the Kentucky Public Service Commission or any other regulatory entity.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the budgeted costs for the Company's Shared Services Unit ("SSU") for the base period and forecasted test period in this rate proceeding. As described more particularly in the testimony of Company witnesses Mr. Daniel Meziere and Mr. James Cagle, SSU provides support (accounting, legal, customer support, etc.) to the Company's various utility divisions and subsidiaries. SSU costs incurred for providing these services are allocated to the utility divisions and subsidiaries according to the allocation process and methodology described by Mr. Meziere and Mr. Cagle. The total SSU forecasted costs determined in accordance with the processes described in my testimony, before cost allocation, are reflected in the Company's rate filing in this proceeding. The amount of the SSU operating and maintenance (O&M) costs allocated to the Company's Kentucky/Mid-States Division and to its Kentucky utility operations, through the process and methodology described by Mr. Meziere and Mr. Cagle, are sponsored by Mr. Waller in his testimony as part of the costs included in the Company's rate filing. The amount of the SSU capital expenditure (Capex) included in rate base allocations through the process and methodology described by Mr. Cagle are sponsored by Mr. Thomas Petersen and Mr. Robert W. Cook, Jr.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENT IN THIS CASE, AND, IF SO WHICH REQUIREMENTS?

A. I am not specifically sponsoring any of the filing requirements. However, I am providing supporting testimony to those witnesses sponsoring allocated SSU costs (Mr. Waller, Mr. Cook and Mr. Petersen) included within the Company's rate filing, and to those witnesses sponsoring forecasted test period operating and maintenance costs (Mr. Waller) and forecasted test period capital expenditures (Mr. Cook) developed based upon the Company budgeting and financial forecasting processes herein described.

III. SSU BUDGETING PROCESS

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S BUDGETING PROCESS?

A. The objectives of the Company's budgeting process are to formalize the process of identifying the anticipated costs for the Company's operations and anticipated capital expenditures. In this process, my department provides support to the SSU cost center owners and the management of each utility division and subsidiary of the Company in the development of their budgets and we ensure that the policies and procedures associated with the annual budgeting process are adhered to. The budgeting process also assesses the appropriateness of costs to ensure that anticipated expenditures do not exceed a level which is reasonably necessary for the Company's operations, including the Company's ability to deliver safe, reliable and efficient natural gas services to its customers. The Company's budgeting process also ensures that the budget properly reflects the Company's strategic operational and financial plans.

Q. HOW DOES THE BUDGETING PROCESS WORK?

A. The O&M budgeting process is fully described in Mr. Waller's direct testimony. The Capex budgeting process is fully described in Mr. Cook's direct testimony. The annual SSU budget for both O&M and Capex described by these witnesses is developed using the same methods, processes and controls.

Q. PLEASE DESCRIBE THE SSU BUDGETING PROCESS.

A. Perhaps the easiest way to explain the SSU process is to begin with a brief explanation of how SSU is organized. SSU is comprised of functional service groups such as my department and others, including accounting, legal, rates, information technology, customer support, risk management, etc. Each functional service group is comprised of one or more cost centers, such as accounting which, at the high level, consists of the Company's controller, general accounting services, tax services, revenue accounting and financial reporting. These cost centers may have additional cost centers below them which roll up into the cost center for total budgeting purposes, such as plant accounting within general accounting. In addition to working with and supporting the Company's utility divisions and subsidiaries during the annual budgeting process, we also work with and support the SSU cost center owners in the development of their annual budgets.

Each cost center owner, whether an officer, managerial director, manager or supervisor of the Company, is responsible for developing his or her annual budget as part of the Company-wide annual budgeting process, except for certain pre-determined costs developed by my group or another group that has knowledge of the pre-determined cost. An example of a pre-determined cost is the allocated portion of corporate office rent. Pre-determined costs are provided to cost center owners for inclusion in their cost center budgets.

Once an SSU cost center budget has been prepared, it is subject to the same managerial review and approval processes described in the testimony of Mr. Waller that are used for the budgets of the Company's utility divisions and subsidiaries.

Once approved, the SSU cost center's budget is subject to the same ongoing control processes, including variance monitoring, described in Mr. Waller's testimony.

Q. HOW DOES BUDGETING FOR SSU CAPEX DIFFER FROM CAPEX BUDGETING BY A UTILITY DIVISION SUCH AS THE KENTUCKY/MID-STATES DIVISION?

A. Although a particular Capex item may be budgeted by an SSU cost center owner, such as the purchase of a new filing cabinet, the majority of SSU Capex costs consist of information technology hardware and software systems. These costs are budgeted in the SSU Information Technology (IT) costs centers. For example, if tax services required a new property tax management system, then the IT group would work with tax services to budget the costs of purchasing or developing and implementing the new system. IT will include these costs as part of the IT Capex budget for SSU information technology capital projects. The SSU Capex budget is subject to the same managerial review and pre-approval processes, as well as ongoing control processes, described in Mr. Cook's testimony.

Q. HOW ARE THE COSTS IN AN SSU COST CENTER BUDGET CHARGED OR ALLOCATED TO THE COMPANY'S UTILITY DIVISION, SUCH AS IN KENTUCKY?

A. For O&M costs, the Company employs a process of common cost allocation that is described in the direct testimony of Mr. Meziere and Mr. Cagle. For illustrative purposes only, if the SSU tax services cost center budgeted $100,000 in O&M for a fiscal year and the applicable allocation factor for Kentucky were 5%, then Kentucky would be allocated $5,000 of tax services budgeted O&M. Of course, budgeted allocation amounts are based upon actual budget numbers and actual allocation factors.

Unlike O&M, SSU Capex is not directly charged to the Company's utility divisions or subsidiaries. Once an SSU capital project is completed and closed to plant, it then becomes part of SSU general plant that is allocated for ratemaking purposes within a rate filing as more particularly described by Mr. Cagle. In this rate filing, increases to SSU general plant for the forecasted test period pertain to spending on capital projects which are reasonably expected to be closed to plant and in service for the benefit of our utility divisions, including the Kentucky/Mid-States Division, before the end of the forecasted test period.

Q. HAVE ALLOCATED SSU COSTS BEEN INCLUDED AS PART OF THE FORECASTED TEST PERIOD COSTS FOR PURPOSES OF THIS RATE FILING?

A. Yes. My group developed the forward-looking SSU costs (both O&M and Capex) for purposes of the forecasted test period used for this rate filing. The entirety of these forecasted costs are not attributable to Kentucky, only an allocated portion. The allocated costs were determined according to the cost allocation process described by Mr. Meziere and Mr. Cagle and are incorporated into the filing requirements sponsored by Mr. Waller (O&M) and Messrs. Cook and Petersen (Capex).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF RATE APPLICATION OF ATMOS ENERGY CORPORATION	)))	Case No. 2006-00464

CERTIFICATE AND AFFIDAVIT

The Affiant, Daniel M. Meziere, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

STATE OF Texas
COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by Daniel M. Meziere on this the 18th day of December, 2006.

Dwala Kuhn
Notary Public
My Commission Expires: ____________

DWALA KUHN
NOTARY PUBLIC
State of Texas
Comm. Exp. 08-27-2009

DWALA KUHN
NOTARY PUBLIC
State of Texas
Comm. Exp. 08-27-2009

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORTION	)	

TESTIMONY OF DANIEL M. MEZIERE

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel M. Meziere. My business address is 5430 LBJ Freeway, Suite 600, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Accounting Services for Atmos Energy Corporation (hereinafter "Atmos" or the "Company").

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am primarily responsible for directing various accounting activities and policies within the Company. My primary duties include the oversight of general accounting, fixed assets accounting, accounts payable, payroll, and cost allocations. I also serve on an internal committee which is responsible for the oversight and monitoring of Sarbanes-Oxley (SOX) compliance. In addition, I work with both our internal and external auditors on implementing, testing, maintaining and modifying the Company's accounting controls, as well as interfacing between the auditors and the Company.

I am also responsible for ensuring effective financial and internal controls for the Company's accounting processes, system and procedures. I have knowledge of the Company's accounting activities, which include compiling, processing, reporting and analyzing financial information to satisfy the requirements of internal management, internal independent auditors, external independent auditors and regulatory agencies.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Accounting from East Central Oklahoma State University in 1983 and a Masters of Business Administration from the University of Dallas in 1997.

I have worked in the energy industry for almost 20 years in a variety of accounting and finance positions. I joined Atmos Energy Corporation in 2002 in my current position.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am licensed by the State of Oklahoma as a Certified Public Accountant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION OR OTHER REGULATORY ENTITIES?

A. I have not testified before the Kentucky Public Service Commission. However, I have testified before the Georgia Public Service Commission in Docket No. 20298-U, the Missouri Public Service Commission in Docket No. GR-2006-0387, the Railroad Commission of Texas in Docket No. 9676 and the Tennessee Regulatory Authority in Docket 05-00258.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to authenticate the historic books and records of the Company and demonstrate the integrity of the financial information that has been filed in this case. I am also providing testimony concerning the Company's Cost Allocation Manual (CAM) which describes the methodology for shared services cost allocations.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENT IN THIS CASE, AND, IF SO WHICH REQUIREMENTS?

A. Yes, I am sponsoring the following specific filing requirements of Section 10 of 807 K.A.R. 5:001[1]:

FR 10(1)(b)(2)	Statement that annual reports are on file with the Commission;
FR 10(9)(j)	The prospectus of the most recent stock offering;
FR 10(9)(k)	Calendar year 2005 FERC Form 2;
FR 10(9)(l)	Annual reports to shareholders and statistical supplements for the preceding five years;
FR 10(9)(m)	Current chart of accounts;
FR 10(9)(p)	The Securities and Exchange Commission filings on Form 10-K and Form 8-K for the prior two years and the From 10-Q for the past six quarters;
FR 10(9)(q)	Independent auditors annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls; and
FR 10(9)(r)	Quarterly reports to stockholders for the most recent five quarters.[2]

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes

III. AUTHENTICATION OF BOOKS AND RECORDS

Q. ARE THE BOOKS AND RECORDS OF THE COMPANY PREPARED UNDER YOUR DIRECTION?

A. Yes, for the areas under my direction (which do not include gas accounting or taxation).

Q. HOW DOES ATMOS MAINTAIN AND UTILIZE ITS BOOKS AND RECORDS IN THE REGULAR COURSE OF BUSINESS?

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[1] This regulation prescribes numerous filing requirements (FRs). The FR abbreviations used are to the applicable subparts of Section 10 of 807 K.A.R. 5:001.

[2] Other than its quarterly report on Form 10-Q filed with the Securities and Exchange Commission, the Company does not publish quarterly reports to shareholders. Accordingly, no information is actually provided pursuant to FR 10(9)(r) because the Forms 10-Q are provided pursuant to FR 10(9)(p).

A. Atmos maintains its books and records in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) and Generally Accepted Accounting Principles (GAAP). The USOA is the prescribed methodology for maintaining utility records in all of the state jurisdictions which regulate the Company's natural gas utility operations, which currently include Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Tennessee, Texas and Virginia.

Atmos' accounting organization utilizes integrated computerized business systems to efficiently process, record and maintain transactions generated in the regular course of business. Financial transactions are created and entered into the system at or near the time of the transaction by the responsible personnel in various divisions having personal knowledge, or acting in reliance on information transmitted by persons having personal knowledge of the transactions, as well as of the applicable accounting procedures and requirements. Reports are generated by the system in the regular course of business to assist in management's review of the results of operations and to assist in the analysis of the cost data of gas operations.

Q. AS DIRECTOR OF ACCOUNTING SERVICES, HOW DO YOU ASSURE YOURSELF THAT TRANSACTIONS ARE RECORDED PROPERLY?

A. As Director of Accounting Services, I have personal knowledge of the organizational business processes and staffing in the Controllership function. The Controller's organization is staffed with highly qualified accounting managers and staff, with many accounting positions filled by CPAs. The managers in the organization are charged with the responsibility to inspect, review and revise, if appropriate, the work of the accountants they supervise. To fill certain management positions, an individual is required to have an accounting degree as well as significant accounting experience. We have established and maintained controls that ensure the accuracy of our books and records. These controls help identify any necessary adjustments to accounting entries which are then recorded to the original books and records in a timely manner. Additionally, Atmos contracts with KPMG for internal audit services. This group periodically performs reviews of those controls.

Q. WHAT TYPES OF REGULAR AUDITS ARE CONDUCTED TO AUTHENTICATE ATMOS ENERGY'S BOOKS AND RECORDS?

A. Atmos' books and records are audited annually by the independent public accounting firm of Ernst & Young LLP. In addition, Ernst & Young LLP also performs reviews of Atmos' quarterly financial statements. These audits and reviews are conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

IV. COST ALLOCATION MANUAL

Q. WHAT IS THE COST ALLOCATION MANUAL?

A. The Cost Allocation Manual (CAM), contained in Exhibit DMM-1, describes and documents the process whereby allocations are made within the books and records of the Company. These include allocations of various common expenses which are incurred for the benefit of two or more of the Company's rate divisions and are therefore allocable to those rate divisions. Additionally, the CAM also describes and documents the processes whereby allocations are made between Atmos and its affiliates and between affiliates.

Q. ARE YOU RESPONSIBLE FOR OVERSIGHT OF THE CAM?

A. Yes. I coordinate and oversee the updating and filing of the CAM.

Q. PLEASE DESCRIBE THE HISTORY OF THE CAM.

A. Although the Company had been utilizing the allocation methodology described in the CAM for many years prior, the CAM was formally documented in response to 807 K.A.R. 5:080, and was first filed with the Commission in April of 2001. Atmos is required to update the CAM each year. The Company has used the CAM to document its allocation processes in the regular course of business since it was first filed.

Q. ARE THE ALLOCATIONS DESCRIBED IN THE CAM USED IN EVERY JURISDICTION IN WHICH ATMOS ENERGY OPERATES?

A. Yes. The CAM is uniformly applied in all twelve states in which Atmos has regulated utility operations for the allocation of common costs among Atmos' various operating divisions, including Kentucky.

Q. DOES THE CAM DESCRIBE HOW TO ALLOCATE BALANCE SHEET AMOUNTS?

A. No. The CAM describes how to allocate expense items from Atmos' income statement. Investment or balance sheet items are not allocated within Atmos Energy's books and records. Investment amounts are allocated only for ratemaking purposes in the context of a rate filing or certain regulatory reports. Atmos witness James C. Cagle is providing testimony on the appropriate allocation of shared services investment or ratebase amounts in this filing, including the Company's allocation of shared costs.

Q. IN YOUR OPINION, DOES THE COMPANY'S ALLOCATION PROCESS UNIFORMLY AND CONSISTENTLY ALLOCATE COMMON OR SHARED SERVICES COSTS?

A. Yes, the allocation process described in the CAM operates fairly and reasonably in allocating those costs on a uniform basis, both as between Atmos' various operating divisions and affiliates and between the various regulatory jurisdictions in which the Company operates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT DMM-1

ATMOS ENERGY CORPORATION
COST ALLOCATION MANUAL
May 1, 2006

TABLE OF CONTENTS

1. Introduction:

a. Corporate Structure

Atmos Energy Corporation ("Atmos") operates its utility business in twelve states through eight operating divisions. The operating divisions are divisions of Atmos and are not subsidiaries or separate legal entities. The operating divisions are Mid-Tex and West Texas Divisions through which Atmos operates in Texas; Colorado-Kansas Division through which Atmos operates in Kansas, Colorado and a small portion of the Company's Missouri operations; Louisiana Division through which Atmos operates in Louisiana; Mid-States Division through which Atmos operates in Tennessee, Georgia, Missouri, Virginia, Illinois and Iowa; Kentucky Division through which Atmos operates in Kentucky; Mississippi Division through which Atmos operates in Mississippi and Atmos Pipeline-Texas Division through which Atmos operates its intrastate pipeline business in Texas. The operating divisions are not separate legal entities, and therefore, by definition, cannot be affiliates of Atmos.

Technical and support services are provided to the operating divisions by centralized shared services departments at the Atmos headquarters in Dallas. These centralized functions include, but are not limited to, accounting, human resources, legal, rates and the Customer Support Centers. The costs for these shared services are allocated to the operating divisions. In addition, for operating divisions that operate in more than one jurisdiction, costs from the operating division general office are allocated to separate rate divisions within the operating division.

In addition to its utility business, Atmos also has non-utility operations. The non-utility business is operated through a number of subsidiaries, which are separate legal entities and one division. A chart showing Atmos' current organizational structure is contained in Appendix A. As the organizational structure indicates, Atmos Energy Corporation owns 100% of Mississippi Energies, Inc , Blueflame Insurance Services, LTD, PDH I Holding Company, Inc, and Atmos Energy Holdings, Inc. Atmos Energy Holdings, Inc., is the sole owner of Egasco, LLC, Atmos Pipeline and Storage, LLC, Atmos Energy Services, LLC, Atmos Power Systems, Inc., Atmos Energy Marketing, LLC, Enermart Energy Services Trust and United Cities Propane Gas, Inc.. Atmos Pipeline and Storage, LLC, is the sole owner of WKG Storage, Inc., Trans Louisiana Gas Storage, Inc., UCG Storage Inc., Atmos Exploration and Production, Inc. and Trans Louisiana Gas Pipeline, Inc. Atmos Energy Services, LLC, is the sole owner of Energas Energy Services Trust. Mississippi Energies, Inc. holds an equity interest in Legendary Lighting, LLC (50%) and Unitary GH&C Products, LLC (28%).

Please note. The descriptions contained herein do not address tariffed services

b. Accounting:

Atmos' account coding structure enables it to capture the costs for allocable activities. Expenses, Assets, and Liabilities for Atmos' shared services and other operating division general and regional office divisions are coded to applicable location codes and cost centers which are then allocated to the appropriate rate divisions based upon the methodologies described herein.

Atmos account coding structure is as follows:

XXX.	XXXX.	XXXX.	XXXXX.	XXXXXX.	XXXX.
Company 3 digit	Cost Center 4 digit	FERC Account 4 digits	Sub- Account 5 digits	Service Area 6 digits	Future Use 4 digits

Within the above coding structure, "Company" and "Cost Center" are primarily utilized for management reporting purposes and reflects the internal management "cost responsibility" structure of Atmos Energy Corporation, exclusive of its subsidiaries. The term "Company" as utilized for account coding refers to a subsidiary or separate legal entity or to one of the Company's various eight operating divisions and under which Atmos conducts the vast majority of its utility business in twelve states. "Cost Center" addresses departmental cost responsibility and is primarily utilized for budget control purposes. Utilization of the "Company" or "Cost Center" fields is not suitable for financial or regulatory reporting purposes.

The field described by FERC account contains the 3 digit FERC USOA account plus one extension digit which is in some cases utilized by the FERC USOA.

The first three digits of the Service Area field are the primary coding utilized for cost allocations within Atmos and is generally referred to as "rate division number". This portion of the field denotes Atmos' various rate divisions as well as the Company's various shared services, operating division general office and regional office divisions. These codes are the primary source of information for regulatory reporting and rate activity. The remaining 3 digits represent "town" location which is utilized only for some accounts.

c. Glossary of Terms:

Affiliate - For purposes of this document, one or more of Atmos' subsidiaries.

Atmos Pipeline-Texas Division – The operating division within which Atmos Energy Corporation conducts its intrastate pipeline business within the state of Texas.

Below the Line - Amounts which are generally not included in an analysis of costs from which gas service rates are derived.

Colorado-Kansas Division - The operating division within which Atmos Energy Corporation conducts business within the states of Colorado, Kansas and a small portion of the Company's Missouri operation.

Composite Factor - The Company's general allocation factor which is derived for each applicable area based upon the simple average of gross plant in service, average number of customers and direct operation and maintenance expenses as a percentage of the total of each of these items.

Corporate Headquarters - The headquarters of Atmos Energy Corporation in Dallas, Texas.

Cost Centers - Account coding which denotes cost responsibility primarily for management purposes.

Direct Charges - Those charges which may originate at a shared services department, operating division general office division or regional office division which are booked directly to the applicable rate division.

FERC USOA - The Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission.

Kentucky Division - The operating division within which Atmos Energy Corporation conducts business within the Commonwealth of Kentucky.

Louisiana Division - The operating division under which Atmos Energy Corporation does business within the state of Louisiana.

Mid-States Division - The operating division within which Atmos Energy Corporation does business in the Commonwealth of Virginia, the states of Illinois, Iowa, Tennessee, Georgia and the majority of the Company's operations in Missouri.

Mid-Tex Division - The operating division within which Atmos Energy Corporation conducts business within the central part of the state of Texas.

Mississippi Division - The operating division within which Atmos Energy Corporation does business in the state of Mississippi.

Municipal Jurisdiction - For Atmos' operations in Texas, each municipality, which it serves, has original jurisdiction over rates.

Operating Division - The Company's operations within each of its seven utility regional divisions are typically referred to as "operating divisions" in more general discussions or "Company" within the context of Atmos account coding structure. Operating divisions are not subsidiaries or separate legal entities. An operating division contains at least one rate division. Operating divisions with multiple rate divisions have one operating division general office rate division and may also have other regional office rate divisions in addition to rate divisions corresponding to regulatory jurisdictional areas. There is also one non-utility operating division referred to as Atmos Pipeline – Texas.

Operating Division General Office - Administrative offices that are located outside of shared services offices and which serve as the base of operations and central office for each "operating division".

Rate Division - Denotes Atmos' regulatory jurisdictions that are defined by state boundaries, geographic boundaries within states or municipal boundaries within the State of Texas. The term also denotes Atmos' various shared services, operating division general office divisions and regional office divisions. These codes are the primary source for regulatory reporting and rate activity.

Regional Office Divisions - Represents the offices which serve portions of an operating division. See "operating division" as defined above.

Service Area - The portion of the Company's account coding structure of which the first three digits denote rate division. The last three digits of this code denote "town" which is used only in certain instances.

Shared Services - The Company's functions that serve multiple rate divisions. These services include departments such as Legal, Billing, Call Center, Accounting, Rates Administration among others. Shared Services is comprised of Shared Services – General Office and Shared Services – Customer Support

Shared Services – Customer Support – The Company's functions that serve multiple rate divisions. These services include billing, customer call center functions and customer support related services.

Shared Services – General Office – The Company's functions that serve multiple rate divisions. These services include all other functions not encompassed by Shared Services – Customer Support.

Subsidiaries - The Atmos Energy Corporation Subsidiaries are:

Atmos Energy Holdings, Inc.
Atmos Energy Marketing, LLC
Atmos Exploration & Production, Inc.
Atmos Pipeline and Storage, LLC
Atmos Power Systems, Inc.
Atmos Energy Services, LLC
Blueflame Insurance Services, LTD
Egasco, LLC
Energas Energy Services Trust

Enermart Energy Services Trust
Mississippi Energies, Inc.
Trans Louisiana Gas Pipeline, Inc.
Trans Louisiana Gas Storage, Inc.
UCG Storage, Inc.
WKG Storage, Inc.
Legendary Lighting, LLC (50%)
PDH I Holding Company, Inc.
Unitary GH&C Products, LLC (28%)
United Cities Propane Gas, Inc.

West Texas Division - The operating division within which Atmos Energy Corporation conducts business within the western part of the state of Texas.

Service:	Capitalized overhead (general)
Description:	Overhead related to capital expenditures
Current Provider of Service	Shared Services Atmos Pipeline – Texas Louisiana Division general office Kentucky Division Mid-States Division general office Colorado-Kansas Division general office Mid-States Division regional offices Mid-Tex Division Mississippi Division
Current Use of Service	Rate divisions
Basis for allocation	Capitalized overhead costs are accumulated by operating division or regional office. Each operating division sets an application rate for the year based on projected expenditures. As expenditures for CWIP are booked, the overhead assigned is applied at the application rate. Periodically, the application rate is reviewed. Shared services overhead is allocated to operating divisions based on operating division capital expenditures.

Service:	Capitalized overhead (West Texas Division)
Description:	Overhead related to capital expenditures
Current Provider of Service	West Texas Division general office
Current Use of Service	West Texas rate divisions
Basis for allocation	Capitalized overhead costs are accumulated at the operating division level. The West Texas Division sets an application rate for the year based on projected expenditures for non-irrigation rate divisions. As expenditures for CWIP are booked, the overhead assigned is applied at the application rate. Periodically, the application rate is reviewed. At year-end, a total overhead amount is applied to capital expenditures in the irrigation rate division based on proportion of irrigation customers served to the West Texas Division customers served.

Service:	Stores overhead
Description:	Overhead related to inventory warehousing is allocated to materials as issued.
Current Provider of Service	Shared Services Operating division general office
Current Use of Service	Atmos Pipeline – Texas West Texas Division rate divisions Louisiana Division rate divisions Kentucky Division rate division Mid-States Division rate divisions Mid-Tex Division rate division Colorado-Kansas Division rate divisions Mississippi Division rate division
Basis for allocation	Overhead costs for inventory items, including rent, labor, supervision and adjustments are accumulated by operating division. Each operating division sets an application rate for the year based on projected overhead and materials activity. As materials are issued from the warehouse, the overhead assigned is also allocated to the same account. Periodically, the balance in the undistributed stores overhead account is compared to the materials on hand balance and a new rate is determined. Shared Services stores overhead is allocated monthly to the operating divisions based on number of meters.

Service:	Expenses in Shared Services – Customer Support cost centers
Description:	Includes all expenses for Customer Support.
Current Provider Of Service	Shared Services
Current Use of Service	West Texas Division Mid-Tex Division Louisiana Division Kentucky Division Mid-States Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs allocated from the Shared Services – Customer Support are allocated based on number of customers utilizing these services.

Service:	Expenses in Shared Services – General Office cost centers
Description:	Includes all expenses in Shared Services – General Office.
Current Provider Of Service	Shared Services
Current Use of Service	Atmos Energy Holdings, Inc Atmos Energy Marketing, LLC Atmos Power Systems, Inc Atmos Pipeline and Storage, LLC UCG Storage, Inc WKG Storage, Inc Atmos Energy Services, LLC Egasco, LLC Atmos Exploration and Production, Inc Trans Louisiana Gas Storage, Inc Trans Louisiana Gas Pipeline, Inc Enermart Energy Services Trust Energas Energy Services Trust West Texas Division Mid-Tex Division Atmos Pipeline - Texas Louisiana Division Kentucky Division Mid-States Division Colorado-Kansas Division Mississippi Division Mississippi Energies, Inc.
Basis for allocation	Costs are allocated to affiliates and operating divisions based on a composite factor applied to the Shared Services departments. Shared Services departments which provide services to the Company's affiliates utilize a composite factor the computation of which includes the affiliates (If Mid-Tex and Pipeline are provided services by a department the composite factor will included Mid-Tex and Pipeline at a 25%, 50%, 75% or 100% rate depending on how much service the department provides) . Shared Services departments that do not provide services to the Company's affiliates utilize a composite factor the computation of which does not include the Company's affiliates (If Mid-Tex and Pipeline are provided services by a department the composite factor will included Mid-Tex and Pipeline at a 25%, 50%, 75% or 100% rate depending on how much service the department provides) . Costs for Overhead capitalized are allocated using the rate of shared service O&M expenses charged to each affiliates and operating divisions.

Service:	SSU – Customer Support depreciation and taxes other than income taxes
Description:	Includes all depreciation and taxes other than income tax charged in Shared Services – Customer Support.
Current Provider Of Services	Shared Services
Current Use of Service	West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs are allocated to the divisions in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions.

Service:	SSU – General Office depreciation and taxes other than income taxes
Description:	Includes all depreciation and taxes other than income tax charged in Shared Services – General Office.
Current Provider Of Services	Shared Services
Current Use of Service	Atmos Pipeline – Texas West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs are allocated to the divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each operating division unit as a percentage of the total Direct Property Plant and Equipment in all of the operating divisions. The number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. The total direct O&M expense in each operating division as a percentage of the total direct O&M expense in all operating divisions.

Service:	West Texas Division general office expenses to municipal rate division levels.
Description:	Allocation of general office costs to rate division levels
Current Provider of Service	West Texas Division general office
Current Use of Service	West Texas Division rate divisions
Basis for allocation	Costs are allocated to the rate divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each rate division as a percentage of the total Direct Property Plant and Equipment in the West Texas Division rate divisions. The number of customers in each rate division as a percentage of the total number of customers in the West Texas Division rate divisions. The total direct O&M expense in each municipal rate division as a percentage of the total direct O&M expense in the West Texas Division rate divisions.

Service:	West Texas Division rent expenses.
Description:	Charge for rent expenses related to employees physically located in the West Texas Division
Current Provider of Service	West Texas Division
Current Use of Service	Atmos Energy Services, LLC
Basis for allocation	A charge for rent, utilities and office equipment usage will be billed based on the amount of space in the West Texas Division office occupied by Atmos Energy Services employees.

Service:	Colorado-Kansas Division general office expenses to state regional office division level.
Description:	Allocation of division general office costs to state regional office division levels
Current Provider of Service	Colorado-Kansas Division general office
Current Use of Service	Colorado-Kansas Division regional office divisions
Basis for allocation	Costs are allocated to the states in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each state as a percentage of the total Direct Property Plant and Equipment in Colorado-Kansas Division. The number of customers in each state as a percentage of the total number of customers in Colorado-Kansas Division. The total direct O&M expense in each state as a percentage of the total direct O&M expense in Colorado-Kansas Division.

Service:	Mid-States Division general office and regional office expenses to rate division level
Description:	Allocation of operating division general office costs and regional offices costs to rate division levels
Current Provider Of Service	Mid-States Division general office Mid-States Division regional offices
Current Use of Service	Mid-States Division rate divisions
Basis for allocation	O&M costs are allocated in total based on the average number of customers in each rate division divided by the average total customers encompassed within the Mid-States Division. Depreciation and taxes other than income tax are allocated in total based on the gross plant in each rate division divided by the total gross plant encompassed by the Mid-States Division.

Service:	Louisiana Division general office expenses to rate divisions.
Description:	Allocation of general office costs to rate division levels
Current Provider of Service	Louisiana Division general office
Current Use of Service	Louisiana Division rate divisions
Basis for allocation	Costs are allocated to the rate divisions in total based on 25% going to division 007 and 75% going to division 077.

Service:	Benefits cost allocation
Description:	Accumulates fringe benefits (workers compensation, basic life insurance, SFAS/106, medial/dental insurance, long term disability, ESOP, pension cost etc.) and allocates to the rate jurisdictions and/or subsidiaries.
Current Provider of Service	Shared Services
Current Use of Service	Atmos Pipeline – Texas Division Atmos Power Systems, Inc UCG Storage, Inc Atmos Energy Services, LLC Atmos Energy Marketing, LLC West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Fringe benefits components are accumulated by each operating division general office. Benefit expenses are allocated to rate jurisdictions by multiplying each rate jurisdiction's labor dollars by that particular operating division's benefits load percentage. The load percentage is calculated using total budgeted benefits divided by total labor. An allocation of fringe benefits from Shared Services to the subsidiaries is calculated based on the number of employees of each subsidiary.

Service:	Intercompany labor
Description:	To the extent operating division or affiliate employees provide labor services to another operating division or affiliate the labor costs for the services will be charged to the appropriate operating division or affiliate.
Current Provider of Service	Atmos Energy Services, LLC Louisiana Division Colorado-Kansas Division Mid-States Division Mid-Tex Division Kentucky Division Mississippi Division
Current Use of Service	UCG Storage, Inc. Atmos Pipeline – Texas Division Atmos Energy Marketing, LLC Colorado-Kansas Division Mid-States Division Kentucky Division WKG Storage, Inc Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc. Mississippi Division West Texas Division
Basis for allocation	Labor charges are captured through direct time sheet entries and transferred to the appropriate operating division or subsidiary receiving the labor services.

Service:	Intercompany labor
Description:	To the extent operating division employees provide services to an affiliate a fee will be charged to the affiliate.
Current Provider of Service	Kentucky Division
Current Use of Service	WKG Storage, Inc
Basis for allocation	For the operation and maintenance of the East Diamond Storage Facilities, WKG Storage, Inc. shall pay Atmos Energy Corporation a monthly fee as set forth in the Natural Gas Storage Field and Pipeline Operations Agreement dated August 1, 2004.

Service:	Vehicle insurance allocation
Description:	Allocation of operating division insurance amortization to cost center and jurisdiction levels
Current Provider of Service	West Texas Division general office Louisiana Division general office Kentucky Division general office Mid-States Division general office Colorado-Kansas Division general office Mississippi Division general office
Current Use of Service	Texas Division rate divisions Louisiana Division rate divisions Kentucky Division rate division Mid-States Division rate divisions Colorado-Kansas Division rate divisions Mississippi Division rate division
Basis for allocation	Insurance costs are accumulated to the operating division general office and allocated monthly using the ratio of rate division vehicle expense to total operating division vehicle expense.

Service:	Installing yard lines
Description:	Includes all costs incurred by the operations of the Kentucky Division to install customer-owned yard line. In Kentucky, Atmos does not own the yard line and the work it conducts on such yard lines is not regulated for ratemaking purposes.
Current Provider of Service	Kentucky Division
Current Use of Service	Kentucky Division
Basis for allocation	Materials and labor (including overheads) are charged to other expense below the line. Use of transportation or work equipment is recorded in the same account by journal entry based on actual usage. Billing to the customer is reclassed from revenue to other income below the line.

Service:	Bad debt expense allocation
Description:	Allocation of operating division bad debt expense amortization to cost center and jurisdiction levels
Current Provider of Service	West Texas Division general office Louisiana Division general office Mid-States Division general office Colorado-Kansas Division general office
Current Use of Service	West Texas Division rate divisions Louisiana Division rate division Mid-States Division rate divisions Colorado-Kansas Division rate divisions
Basis for allocation	Bad debt expense is accumulated to the operating division general office and allocated monthly using the ratio of rate division gross sales to total operating division gross sales.

Service:	Adjustments to Uncollectible Accounts Expense
Description:	Allocation of additional expense amounts booked to adjust the Provision for Uncollectibles (Account 144)
Current Provider of Service	Operating Division General Office
Current Use of Service	West Texas Division rate divisions Louisiana Division rate divisions Mid-States Division rate divisions Colorado-Kansas Division rate divisions
Basis of Intra-company Allocations	Costs are allocated to the rate divisions in total based on Sales Revenue.

Service:	Intra-company labor allocation – other than operating division general office labor
Description:	Certain employee activities cross multiple rate divisions within an operating division. The costs associated with such activities include labor, benefits and associated taxes.
Current Provider of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Current Use of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis of Intra-company Allocations	Labor associated with cross-jurisdictional activities is allocated to each jurisdiction based on the level of employee activity. The allocations are captured either through direct time sheet entries or fixed labor distribution percentages.

Service:	Other income and interest expense
Description:	Allocation of Shared Services' other income and interest expense
Current Provider of Service	Shared Services
Current Use of Service	West Texas Division Louisiana Division Kentucky Division Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Interest Expense, Interest Income and Other Non Operating Income in shared services are allocated to each utility division general office based on the budget allocation percentages. The budget allocation is based on net investment by business unit as of the latest month available when the budget is prepared, with normalizing or averaging adjustments to working capital. Net investment is total assets less non-debt liabilities (excluding long-term debt, notes payable and current maturities.) The allocation factors are the same for the whole year

Service:	Retail services marketing support
Description:	Atmos provides certain retail services through partnering with an outside firm, where customers are provided the opportunity to learn about other non-utility services that may be of interest to them.
Current Provider of Service	Shared Services
Current Use of Service	Atmos Energy Services, LLC
Basis for allocation	Costs are charged on a fixed basis. The fixed charge is based on allocation factors applied to the Shared Services departments. Please see "Expenses in Shared Service cost centers", page 10.

Service:	Gas cost between state jurisdictions for contiguous systems.
Description:	Gas costs that apply to contiguous systems that cross state jurisdictional boundaries are allocated between those rate jurisdictions.
Current Provider of Service	West Texas Division Colorado-Kansas Division Mid-States Division
Current Use of Service	West Texas Division Colorado-Kansas Division Mid-States Division
Basis of Allocations	Allocations are based upon throughput for the West Texas Division and the Colorado-Kansas Division's Southeast Colorado/Southwest Kansas operations. For the Colorado-Kansas Division's Kansas/Missouri system and for the Mid-States Division, demand costs are allocated based on peak-day requirements. Commodity costs are allocated based upon throughput.

Service:	Gas storage services between an operating division and an affiliate
Description:	To the extent an operating division stores gas in a storage field owned by an affiliate, a rental fee for the use of the storage field shall be charged by the affiliate.
Current Provider of Service	UCG Storage, Inc.
Current Use of Service	Mid-States Division
Basis for allocation	An annual demand charge for the operating division is calculated based on fiscal year plant in service, gas inventory, actual operational costs incurred, and application of revenue and cost of capital conversion factors based on prior regulatory approval. In the calculation of the demand charge costs not specifically related to a designated area are allocated to each affiliate based on percentage of total plant servicing that affiliate.

Service:	Allocation of lost & unaccounted (L&U) storage gas
Description:	Lost & unaccounted (L&U) gas related to an affiliate's gas storage field is allocated to all affiliates and operating division that store gas in the field.
Current Provider of Service	UCG Storage, Inc.
Current Use of Service	UCG Storage, Inc. Mid-States Division
Basis for allocation	Lost & unaccounted (L&U) gas related to an affiliate's gas storage field is calculated by a third party on an annual basis and is allocated to all relevant subsidiaries and operating divisions that utilize the field for storage. The amount of L&U allocated is based on each subsidiary or operating division's average of the total volumes.

Service:	Gas supply services
Description:	Purchase, management and administration of gas supply arrangements
Current Provider of Service	Atmos Energy Marketing, L.L.C. Atmos Energy Services, LLC Trans Louisiana Gas Pipeline, Inc
Current Use of Service	Kentucky Division Mid-States Division Colorado-Kansas Division Louisiana Division Mississippi Division West Texas Division
Basis for allocation	Charges are a result of either an open market bid process or other market based rate.

Service:	Facilities services
Description:	System operating and maintenance services
Current Provider of Service	Louisiana Division
Current Use of Service	Atmos Energy Marketing, LLC
Basis for allocation	Rate per volumetric unit is cost based.

Service:	Working capital funds management
Description:	Funds are invested on behalf of or provided to affiliates based on operations.
Current Provider of Service	Atmos Energy Corporation
Current Use of Service	Atmos Energy Holdings, Inc. Atmos Energy Marketing, LLC Atmos Energy Services, LLC Atmos Power Systems, Inc. Atmos Pipeline and Storage, LLC Atmos Pipeline Texas UCG Storage, Inc. WKG Storage, Inc. Atmos Exploration & Production, Inc. Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Services, LLC Egasco, LLC Enermart Energy Services Trust Energas Energy Services Trust Mississippi Energies, Inc. PDH I Holding Company, Inc United Cities Propane Gas, Inc
Basis for allocation	Interest income or expense is recognized each month at the subsidiaries' level based on the average outstanding balance of each respective inter-company receivable/payable balance and Atmos' average effective rate of short term debt net of commitment fees plus 2.75 basis points.

Service:	Gas sampling analysis
Description:	To the extent an operating division provides gas-sampling analysis to an affiliate, the affiliate is charged a fee for the analysis and related services provided.
Current Provider of Service	Louisiana Division
Current Use of Service	Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Marketing, LLC
Basis for allocation	The gas sampling analysis charge is based on the lesser of cost of service or market rate applicable to the affiliate's location for the services provided. Gas sampling analysis may also include other related services as required such as a moisture test, H_2S, CO_2, sample collection, and mileage.

Service:	Gas storage services provided between affiliates
Description:	To the extent an affiliate stores gas in a storage field owned by another affiliate, a fee for the use of the storage field shall be charged.
Current Provider of Service	WKG Storage, Inc. Trans Louisiana Gas Storage, Inc.
Current Use of Service	Kentucky Division Trans Louisiana Gas Pipeline, Inc.
Basis for allocation	The fee to the affiliate utilizing the storage service is based on services provided at actual cost, market rate, or as otherwise provided under tariff.

Service:	Derivative activities
Description:	Financial and physical derivative activities.
Current Provider of Service	Atmos Energy Services, LLC
Current Use of Service	Mid-States Division Kentucky Division Colorado-Kansas Division Louisiana Division Mississippi Division West Texas Division
Basis for allocation	Transaction fees are determined based on actual cost while carrying costs are based on market.

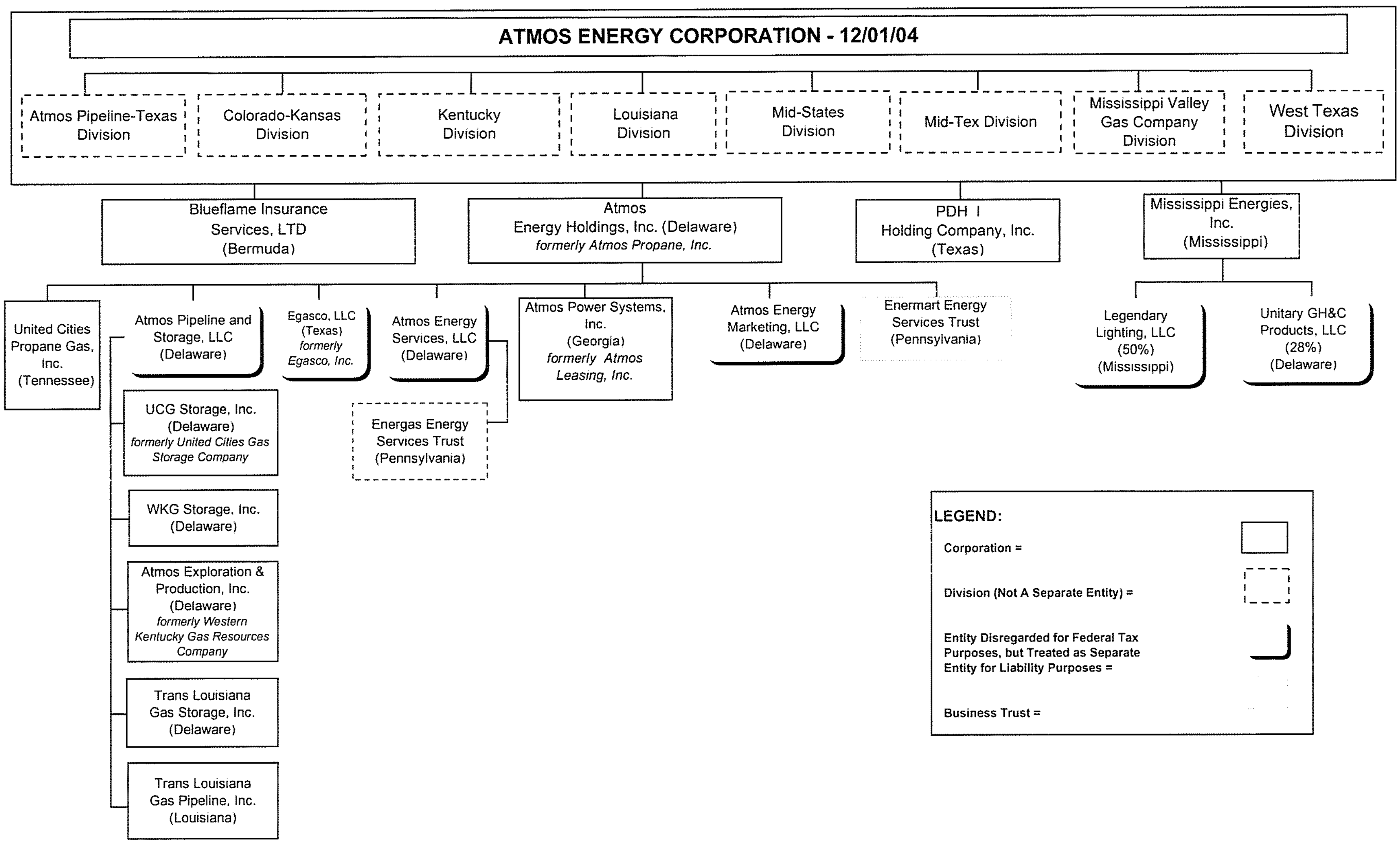
Service:	Storage service to TLGP
Description:	Storage Services
Current Provider of Service	Trans Louisiana Gas Storage, Inc.
Current Use of Service	Trans Louisiana Gas Pipeline, Inc.
Basis for allocation	Charges are based on a market rate.

Service:	Intrastate pipeline service
Description:	Intrastate pipeline service
Current Provider of Service	Trans Louisiana Gas Pipeline
Current Use of Service	Atmos Energy Marketing, LLC Louisiana Division
Basis for allocation	Charges are market based.

Service:	Salaries & benefits cost allocation
Description:	Salaries and benefits (medical insurance, profit sharing plan) cost allocations between affiliates.
Current Provider of Service	Atmos Energy Marketing, L.L.C
Current Use of Service	Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Marketing. LLC Atmos Power Systems, Inc.
Basis for allocation	Costs are allocated based on each individual employee's calculated allocation rate between companies.

Service:	Property Insurance
Description:	Blueflame Insurance Services, LTD. provides a direct property insurance policy. The policy covers the property against all risks of direct physical loss or damage.
Current Provider of Service	Blueflame Insurance Services, LTD
Current Use of Service	Kentucky Division Mid-States Division Colorado-Kansas Division Louisiana Division Mississippi Division Mid-Tex Division West Texas Division Atmos Pipeline – Texas Division Atmos Energy Marketing, LLC Atmos Exploration & Production, Inc. Atmos Pipeline and Storage, LLC Atmos Power Systems, Inc. Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc. UCG Storage, Inc. WKG Storage, Inc.
Basis for allocation	Atmos Energy Corp. is invoiced by Blueflame Insurance Services. Costs are then further allocated based on property value of each affiliate.

Appendix A


ATMOS ENERGY CORPORATION - 12/01/04
Atmos Pipeline-Texas Division
Colorado-Kansas Division
Kentucky Division
Louisiana Division
Mid-States Division
Mid-Tex Division
Mississippi Valley Gas Company Division
West Texas Division
Blueflame Insurance Services, LTD (Bermuda)
Atmos Energy Holdings, Inc. (Delaware) formerly Atmos Propane, Inc.
PDH I Holding Company, Inc. (Texas)
Mississippi Energies, Inc. (Mississippi)
United Cities Propane Gas, Inc. (Tennessee)
Atmos Pipeline and Storage, LLC (Delaware)
UCG Storage, Inc. (Delaware) formerly United Cities Gas Storage Company
WKG Storage, Inc. (Delaware)
Atmos Exploration & Production, Inc. (Delaware) formerly Western Kentucky Gas Resources Company
Trans Louisiana Gas Storage, Inc. (Delaware)
Trans Louisiana Gas Pipeline, Inc. (Louisiana)
Egasco, LLC (Texas) formerly Egasco, Inc.
Atmos Energy Services, LLC (Delaware)
Energas Energy Services Trust (Pennsylvania)
Atmos Power Systems, Inc. (Georgia) formerly Atmos Leasing, Inc.
Atmos Energy Marketing, LLC (Delaware)
Enermart Energy Services Trust (Pennsylvania)
Legendary Lighting, LLC (50%) (Mississippi)
Unitary GH&C Products, LLC (28%) (Delaware)
LEGEND:
Corporation =
Division (Not A Separate Entity) =
Entity Disregarded for Federal Tax Purposes, but Treated as Separate Entity for Liability Purposes =
Business Trust =

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, James C. Cagle, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

STATE OF Texas

COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by James C. Cagle on this the 18th day of December, 2006.

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

Ethel Z. Taylor
Notary Public
My Commission Expires: August 13, 2010

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
	)	
ATMOS ENERGY CORPORTION	)	

TESTIMONY OF JAMES C. CAGLE

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is James C. Cagle. I am the Manager of Rates and Revenue Requirements for Atmos Energy Corporation ("Atmos" or the "Company"). My business address is 5430 LBJ Freeway, Suite 700, Dallas, Texas 75240.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Accountancy degree from the University of Oklahoma in 1987. I am a Certified Public Accountant licensed in the state of Texas. I have been employed by Atmos since 1989. I was initially employed in Atmos' financial reporting department. For the past thirteen years, except for the period from September 1997 through February 1998 when I was employed by GTE in its Costing department, I have worked in Atmos' rates department.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AND QUALIFICATIONS.

A. As Manager of Rates and Revenue Requirements, I am primarily responsible for rate studies of and assisting in the design and implementation of rates for Atmos' regulated utility operations. I am also responsible for oversight of certain rate related compliance and reporting requirements prescribed by Atmos' various regulatory commissions. Part of my responsibilities also include participation in the preparation, updating and implementation of the Company's Cost Allocation Manual (CAM), which is filed at least yearly with the Kentucky Public Service Commission ("KPSC" or the "Commission") and is further discussed in the testimony of Company witness Daniel M. Meziere. For a significant portion of the past thirteen years, I have performed rate studies or portions of rate studies for the design and implementation of rates for a majority of the Atmos' operations.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No. However, I have provided testimony before several state commissions. Exhibit JCC-1 attached hereto lists the various states and dockets in which I have testified.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring the following specific filing requirements of 807 K.A.R. 5:001, Section 10:

FR 10(9) (u) Allocations of common costs from the Company's Shared Services and division general offices for ratemaking purposes as well as charges from affiliates.[1]

FR 10(10)(e) Jurisdictional federal and state income tax summaries.

FR 10(10)(h) Computation of gross revenue conversion factor.

Q. ARE YOU SPONSORING ANY SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

[1] The Company's affiliates that provide or have provided services to the Company's utility operations in Kentucky include Blueflame Insurance Services, Ltd (more particularly described in the direct testimony of Company witness Ms. Laurie Sherwood) and Atmos Energy Services, LLC (more particularly described in the direct testimony of Company witness Gary Smith).

A. Attached to my testimony are Exhibit JCC-1 (described above), Exhibit JCC-2 which shows the Company's overall corporate structure, and Exhibit JCC-3 which sets forth the composite factors used to allocate common costs for purposes of this rate proceeding.

III. ATMOS' CORPORATE STRUCTURE

Q. ARE YOU FAMILIAR WITH THE COMPANY'S CORPORATE STRUCTURE?

A. Yes. Atmos Energy Corporation consists of the utility and various subsidiaries. The utility is the parent Company. The Company conducts its unregulated operations through its subsidiaries. A chart showing the current corporate structure is included as Exhibit JCC-2. .

Q IN THE TOP BOX OF EXHIBIT JCC-2 REPRESENTING ATMOS ENERGY CORPORATION, WHAT DO THE VARIOUS DIVISIONS REPRESENT?

A. The various divisions are a part of the Company's management control structure that is utilized in the Company's shared costs allocation processes. Section 1a of the CAM describes the corporate structure in detail. There are currently seven such divisions – six of which are regulated gas local distribution operations and one of which is a regulated intrastate pipeline operation. We commonly refer to these divisions as "Operating Divisions" or "Business Units". The Company's Kentucky operation is contained within the Kentucky/Mid-States Operating Division/Business.[2] Also, Operating Divisions or Business Units are comprised of rate divisions (described later herein).

Q. DO THESE OPERATING DIVISIONS CONSTITUTE SEPARATE LEGAL ENTITIES?

A. No. They are merely unincorporated operating divisions within the organizational structure that the Company has chosen. None of the Operating Divisions are subsidiary entities that have a separate legal existence apart from the Company, they are not

[2] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated are now, in effect, one division – the Kentucky/Mid-States Division. "Division" as used in my testimony means the Company's Kentucky/Mid-States Division. "Kentucky" when used in my testimony, unless otherwise indicated, refers exclusively to the Company's operations in Kentucky.

distinct legal entities, and they do not have separate equity or debt. Additionally, the divisions do not keep separate books and records.

IV. COST ALLOCATION PROCESS FOR COMMON COSTS

Q. WHAT IS COST ALLOCATION WITH REGARD TO COMMON COSTS?

A. Cost allocation is the process of allocating various common costs that are incurred for the benefit of two or more of the Company's rate divisions and are therefore allocable to those rate divisions.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO "RATE DIVISION"?

A. "Rate division" denotes the Company's regulatory jurisdictions that are defined by state boundaries or, where applicable, geographic areas within states, and which comprise an Operating Division. The term rate division also denotes the Company's various Shared Services, as well as a particular Operating Division's general and regional office rate divisions, whose costs are common to more than one operating rate division and are therefore allocable to those operating rate divisions. For example, an Operating Division may encompass multiple rate divisions, particularly if the operations of the Business Unit include multiple states. Basically, each rate division represents an accumulation of accounting data which is applicable to an area in which rates have been set by a regulatory authority such as the Commission. The Company refers to this accumulated data as a rate division.

Q. ARE THERE DIFFERENT TYPES OF RATE DIVISIONS?

A. Yes, there are operating rate divisions and office rate divisions. An operating rate division represents a regulated operation such as the Company's utility operations in Kentucky. An office rate division is one which provides common services to operating rate divisions (as more fully explained hereinbelow). The costs of the office rate divisions are allocated to the operating rate divisions in accordance with the methodology described by the CAM, as will be more fully explained later in my testimony.

Q. HOW MANY OPERATING RATE DIVISIONS COMPRISE THE COMPANY'S KENTUCKY/MID-STATES DIVISION?

A. Currently, there are thirteen rate divisions in the Kentucky/Mid-States Operating Division, of which Kentucky is one.

Q. HOW DOES THE ACCOUNTING SYSTEM ALLOW FOR THE SEPARATE RECORDING AND TRACKING OF COSTS FOR ATMOS ENERGY'S RATE DIVISIONS?

A. Direct costs are charged directly to the operating rate division which has incurred the costs. For example, if Kentucky hires an outside contractor to perform leak survey services, then those costs are charged directly, and only, to Kentucky because the work is done only for Kentucky. Costs for the Shared Services (hereinafter defined), by contrast, are allocated to the operating rate divisions that receive the benefit of those services. Detailed transactions are recorded by rate division in the general ledger for all utility divisions of Atmos Energy.

Q. WHAT OFFICE RATE DIVISIONS PROVIDE SERVICES TO THE COMPANY'S KENTUCKY RATE DIVISION?

A. Kentucky receives allocations of common costs from Shared Services. Shared Services is comprised of the Shared Services - General Office and Shared Services – Customer Support. Kentucky also receives an allocation of common costs from the Mid-States general office.

Q. WHAT ARE THE COMMON COSTS TO WHICH YOU REFER?

A. Common costs include costs related to technical and support services that are provided to the Company's operating rate divisions by centralized shared services ("Shared Services" or "SSU"). Shared Services – General Office includes, for example, accounting, human resources, legal, rates, information technology and numerous others functions. Shared Services – Customer Support includes customer call center services, billing, collections, and other customer support related functions. The costs for these Shared Services are allocated to the Company's rate divisions.

Q. ARE THERE ADDITIONAL COMMON COST ALLOCATIONS OTHER THAN SHARED SERVICES?

A. Yes. If an office rate division encompasses more than one jurisdiction, such as the Company's Kentucky/Mid-States rate division which provides services to the Company's utility operations in Georgia, Iowa, Illinois, Missouri, Tennessee, Virginia and Kentucky, then the costs from that office rate division are allocated to the separate rate divisions to which it provides services.

Q. DOES THE COMPANY HAVE ANY METHODOLOGY FOR ALLOCATING COMMON COSTS TO A RATE DIVISION?

A. Yes. The rate division designation is incorporated into the Company's account coding string. As such, costs are accumulated for various operating areas or office rate divisions within the Company's general ledger. This could represent the Company's operations in a particular state or a particular area within a state and/or various office rate divisions which would appropriately allocate costs to operating rate divisions.

Q. ARE COMMON COST ALLOCATIONS NECESSARY IN THE CONTEXT OF THE COMPANY'S RATE FILINGS?

A. Yes. It is appropriate and necessary to allocate the common costs incurred for the benefit of ratepayers in multiple regulatory jurisdictions to the various jurisdictions that receive those services. For example, the Company's Shared Services – General Office provides the various support services discussed above to its utility operations in the twelve states in which the Company operates. Some of these shared services are also provided to the Company's unregulated subsidiaries. Similarly, the Shared Services - Customer Support provides customer service functions to the Company's utility operations and is the utility customer's point of contact with the Company for service activations, billing issues, emergency reporting, etc. The Kentucky rate division customers receive the benefits of these services and the allocation of these costs are fairly and justly apportioned to the Kentucky rate division. In addition to Shared Services, the Kentucky/Mid-States Division headquarters office began providing services to Kentucky and as a result, costs from the Kentucky/Mid-States division headquarters office (the Kentucky/Mid-States Division general office rate division) are allocated to the Company's Kentucky rate division beginning October 1, 2006.

Q. PLEASE DESCRIBE THE COMPANY'S COST ALLOCATION METHODOLOGY.

A. The Company allocates certain types of common costs to its operating rate divisions for management purposes as well as for reporting and ratemaking purposes. Operations and Maintenance ("O&M") expense, depreciation expense, and taxes, other than income taxes, expense that represent common costs are allocated on the books of the Company. Other common costs such as commonly utilized plant in service and other ratebase items are not allocated on the books of the Company but are allocated for ratemaking purposes. These costs are allocated based on accepted methodologies which are further outlined below in order to fully show the costs of providing utility service in each of the regulatory jurisdictions within which the Company serves customers.

Q. IN YOUR ANSWER, YOU DIFFERENTIATE BETWEEN COMMON COSTS WHICH ARE ALLOCATED ON THE BOOKS OF THE COMPANY AND THOSE THAT ARE ALLOCATED FOR RATEMAKING PURPOSES. CAN YOU EXPLAIN THE DIFFERENCE?

A. Yes. Operations and Maintenance (O&M) expense, depreciation expense, and taxes, other than income taxes, expense related to Shared Services and the Mid-states division's headquarters office are allocated on the Company's books and records utilizing the allocation methodologies described in detail in the CAM referenced above. The Company allocates these expenses within its books and records as a part of its normal accounting cycle. The allocation factors used are generally calculated once per year, updated at the beginning of the Company's fiscal year (October 1), and utilized for the entire year unless a material event occurs which would significantly change the factors.

For those Shared Services costs which are not allocated on the Company's books and records, either a composite factor for Shared Service – General Office or a customer factor for Shared Service – Customer Support is used to allocate costs. Some examples of Shared Services costs for which composite factors or the customer factor, as appropriate, are used for allocating such expenses for ratemaking purposes would include plant in service and accumulated deferred income taxes, as well as other rate base items.

Q. HOW ARE COMPOSITE FACTORS DERIVED?

A. The composite factors are derived based upon a three-factor formula comprised of:

1. The simple average of the relative percentage of gross plant in service for each of the Company's business units to the total gross plant in service for all of Atmos' business units (excluding Shared Services);

2. The relative percentages of number of customers for each of the Company's business units to the total number of customers for the Company; and

3. The relative percentages of direct O&M expenses for each of the Company's business units to the total direct operation and maintenance expenses of all Atmos' business units (excluding Shared Services).

Q. HOW IS THE CUSTOMER FACTOR DERIVED?

A. The Customer Factor is derived based on the average number of customers of the Operating Divisions that receive allocable costs for the services provided.

Q. WHY IS THE CUSTOMER FACTOR USED TO ALLOCATE SHARED SERVICES – CUSTOMER SUPPORT INSTEAD OF THE COMPOSITE FACTOR?

A. This office rate division provides services exclusively to the Company's regulated utility customers and does not perform any function for the Company's subsidiaries or the pipeline division. As a result, Shared Services – Customer Support costs are allocated only to the Company's regulated local distribution Operating Divisions/Business Units of the Company. The use of the Customer Factor to allocate the costs of this office rate division, instead of the Composite Factors, is reasonable and appropriate because the need for and level of the services required are primarily driven by the number of customers within an Operating Division.

Q. HOW ARE SHARED SERVICES COSTS THEN ALLOCATED OUT TO A RATE DIVISION?

A. Shared Services allocations to the business unit are added to the business unit's general office costs and then further allocated to the applicable office rate divisions within the business unit. For the Kentucky/Mid-States business unit, the factors utilized for further allocating applicable Shared Services and Kentucky/Mid-States general office costs are based on the composite factor developed utilizing the same formula as described above but limited to only those jurisdictions which are served by the Kentucky/Mid-States

General Office. Other costs not allocated on the Company's books and records are also allocated using the same methodology.

Q. HOW ARE SHARED SERVICES COSTS ALLOCATED WITHIN THE COMPANY'S KENTUCKY RATE FILING?

A. O&M expense, depreciation expense, and taxes, other than income taxes, are allocated in the Company's filing utilizing the methodologies memorialized in the CAM. As previously stated, the Company does not allocate ratebase items for Shared Services (such as plant in service or accumulated deferred income taxes) within its books and records. Instead, these items are allocated in the context of rate proceedings such as this one and for certain reporting purposes. In this filing, ratebase items and ratemaking adjustments were allocated utilizing the composite factors set forth and described in Exhibit JCC-3 attached to my testimony. Such composite factors were derived utilizing the methodology described herein.

V. CHARGES FROM AFFILIATES.

Q. DOES THE COMPANY'S KENTUCKY OPERATIONS RECEIVED CHARGES FROM AFFILIATES?

A. Yes. As stated previously, the Division and Kentucky both receive services from Blueflame Insurance Services, Ltd. ("Blueflame") for property insurance. The specific services provided by Blueflame, as well as the basis for the determination of the premiums charged by Blueflame, is addressed in the direct testimony of Ms. Laurie Sherwood. The Division and Kentucky have also received gas supply procurement and management services from Atmos Energy Services, LLC ("AES"), but AES will no longer provide such services from and after January 1, 2007. The services which AES has performed for the Division and Kentucky, as well as the Company's organizational changes which will supplant AES, are addressed in the direct testimony of Mr. Gary Smith.

Q. WILL THESE ORGANIZATIONAL CHANGES HAVE ANY EFFECT UPON COMMON COST ALLOCATION?

A. Yes. As discussed in the direct testimony of Mr. Greg Waller, he has removed the costs to be charged by AES to the Kentucky/Mid-States Division for purposes of the forecasted test period used in this rate filing. The costs associated with the gas supply procurement and management function for the Division are included as part of the SSU costs allocated to the Division and to Kentucky for purposes of the forecasted test period in accordance with the common cost allocation methodology I have described above.

Q. HOW ARE PROPERTY INSURANCE PREMIUM COSTS FROM BLUEFLAME ALLOCATED FOR PURPOSES OF THIS RATE FILING?

A. For property insurance which covers the Company's assets in Kentucky, Kentucky receives a direct charge from Blueflame based upon Kentucky's gross plant as more particularly described in Ms. Sherwood's direct testimony. Direct charges from Blueflame to Kentucky for property insurance for the forecasted test period are part of Kentucky's budgeted costs sponsored by Mr. Waller.

For property insurance which covers the assets of the Kentucky/Mid-States general office rate division, the Division receives a charge from Blueflame based upon the Division's general office rate division gross plant. Kentucky, in turn, receives an allocated portion of this cost from the general office rate division in accordance with the allocation methodology I have described herein which allocates general office rate division costs to the various rate divisions within the Kentucky/Mid-States Division that receive services from the Division's general office. The insurance costs allocated to Kentucky by the Kentucky/MidStates general office rate division for the forecasted test period are part of the budgeted costs therefore sponsored by Mr. Waller.

For property insurance which covers the assets of the SSU gross plant, the two SSU rate divisions, SSU – General Office and SSU – Customer Support, each receive a charge from Blueflame for property insurance coverage based upon the respective SSU rate division's gross plant. These insurance costs are then allocated as part of operating and maintenance costs to the Company's utility divisions and subsidiaries served by those SSU rate divisions in accordance with the applicable allocation methodology described hereinabove. The insurance costs allocated to Kentucky by SSU – General Office and

SSU – Customer Support are part of the SSU costs budgeted for the forecasted test period as described by Mr. Joel Bradshaw.

V. ACCUMULATED DEFERRED INCOME TAX

Q. DOES THE COMPANY'S RATE FILING REFLECT A PROJECTION OF ACCUMULATED DEFERRED INCOME TAX (ADIT)?

A. Yes. The Company's income tax department provided a projection of ADIT for purposes of this filing.

Q. WERE ANY ITEMS EXCLUDED FROM THIS PROJECTION?

A. Yes. Beginning October 2006, within the base period, this projection excludes any estimated amount for over/under recovery of gas cost in order to normalize the tax effect of over/under recovery of gas cost to zero. Additionally, the projection excludes book to tax differences in Shared Services which specifically relate to jurisdictions other than Kentucky.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT JCC-1

DOCKET	TESTIMONY STYLED AS	TYPE	DATE
Virginia Corporation Commission			
PUE 000171	Atmos Energy Corporation for an increase in rates.	Direct	March-00
PUE 2003-00507	Atmos Energy Corporation for an increase in rates.	Direct	February-04
Colorado Public Utility Commission			
00S-668G	In the matter of the tariff sheets filed by Greeley Gas Company, a Division of Atmos Energy Corp with Advice Letter No. 419 regarding comprehensive changes to the rates, terms and conditions for natural gas sales, and transportation services	Direct	November-00
Kansas Corporation Commission			
03-ATMG-1036-RTS	In the Matter of the Application of Atmos Energy for Adjustment of its Natural Gas Rates in the States of Kansas	Direct and Rebuttal	June-03
Railroad Commission of Texas			
9002 – 9135	Statement of Intent Filed by Energas Company to Increase Rates Charged in the 67 West Texas Cities: Petition by Energas for Review of 67 Municipal Rate Decisions	Direct and Rebuttal	March-00
9670, 9676	Petition for de novo review of the reduction of the gas utility rates of Atmos Energy Corp., Mid-tex division, by the cities of Addison, Benbrook, Blue Ridge, Et Al., and statement of intent filed by Atmos Energy Corp., Mid-tex division to change rates in the company's statewide gas utility system.	Direct	May-06
Louisiana Public Service Commission			
U-21922, U-23508 Consolidated	Louisiana Public Service Commission, ex parte, Consolidated Docket U-21922 and U-23508, In re: Docket No. U-21922, In re: Investigation of the Rates and Charges of Trans Louisiana Gas Company, A Division of Atmos Energy Corp. etc.	Direct and Rebuttal	March-99
U-28814	Petition of Trans Louisiana Gas Company, a regulatory division of Atmos Energy Corporation, requesting approval of a Conservation and Consumer Cost Stabilization rider.	Direct	May-05
Georgia Public Utility Commission			
20298-U	Filing of Increased Rates for Natural Gas Service	Direct	May-05
Missouri Public Service Commission			
GR-2006-0387	Atmos Energy Corporation's tariff revision designed to consolidate rates and implement a general rate increase for natural gas service	Direct	April-06

EXHIBIT JCC-2

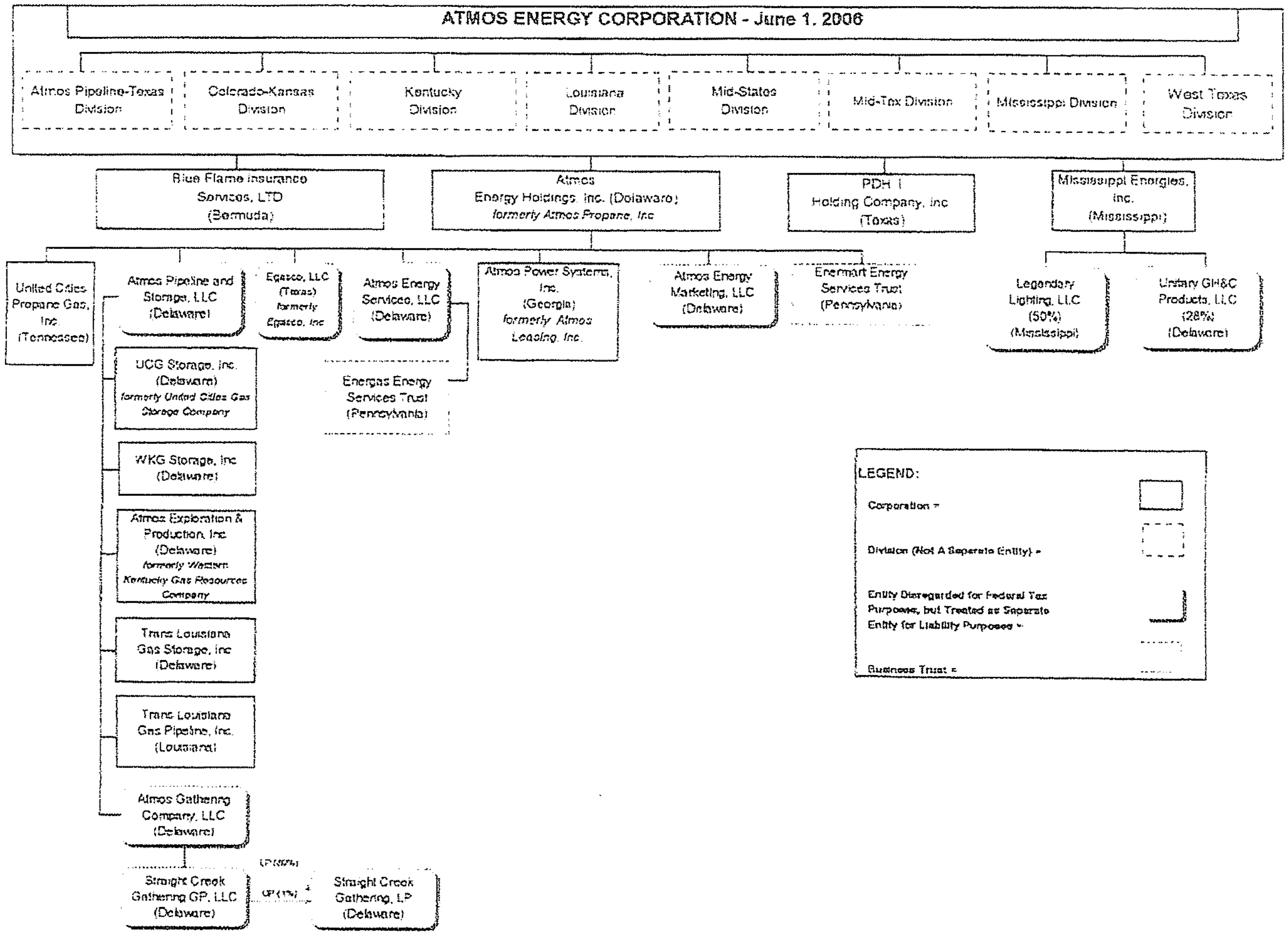

ATMOS ENERGY CORPORATION - June 1, 2006
Atmos Pipeline-Texas Division
Colorado-Kansas Division
Kentucky Division
Louisiana Division
Mid-States Division
Mid-Tex Division
Mississippi Division
West Texas Division
Blue Flame Insurance Services, LTD (Bermuda)
Atmos Energy Holdings, Inc. (Delaware) formerly Atmos Propane, Inc
PDH I Holding Company, Inc (Texas)
Mississippi Energies, Inc. (Mississippi)
United Cities Propane Gas, Inc. (Tennessee)
Atmos Pipeline and Storage, LLC (Delaware)
Egasco, LLC (Texas) formerly Egasco, Inc
Atmos Energy Services, LLC (Delaware)
Atmos Power Systems, Inc. (Georgia) formerly Atmos Leasing, Inc.
Atmos Energy Marketing, LLC (Delaware)
Enermart Energy Services Trust (Pennsylvania)
Legendary Lighting, LLC (50%) (Mississippi)
Unitary GH&C Products, LLC (28%) (Delaware)
UCG Storage, Inc. (Delaware) formerly United Cities Gas Storage Company
Energas Energy Services Trust (Pennsylvania)
WKG Storage, Inc (Delaware)
Atmos Exploration & Production, Inc (Delaware) formerly Western Kentucky Gas Resources Company
Trans Louisiana Gas Storage, Inc (Delaware)
Trans Louisiana Gas Pipeline, Inc. (Louisiana)
Atmos Gathering Company, LLC (Delaware)
Straight Creek Gathering GP, LLC (Delaware)
Straight Creek Gathering, LP (Delaware)
LEGEND:
Corporation =
Division (Not A Separate Entity) =
Entity Disregarded for Federal Tax Purposes, but Treated as Separate Entity for Liability Purposes =
Business Trust =

EXHIBIT JCC-3

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/06

A. Composite Allocation Factor:		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	MidStates Div	KY Div	MVG	Mid-Tex Div	Atmos P/L Mid Tex
Gross Direct PP&E	$	**5,370,692,810**	398,740,964	354,701,307	152,641,872	376,265,849	627,268,359	288,632,910	323,787,054	1,988,757,546	859,896,947
Average Number of Customers	#	**3,090,662**	297,240	235,655	74,661	252,901	291,637	173,204	250,184	1,514,844	336
Total O&M Expense *	$	**328,510,711**	25,920,364	22,493,532	7,426,747	24,809,531	29,107,323	15,205,659	36,818,964	118,929,678	47,798,914
(* w/o Allocation)											
Total Composite Factor											
Gross Direct PP&E	%	**100.00%**	**7.43%**	**6.60%**	**2.84%**	**7.01%**	**11.68%**	**5.37%**	**6.03%**	**37.03%**	**16.01%**
Average Number of Customers	%	**100.00%**	**9.63%**	**7.62%**	**2.42%**	**8.18%**	**9.44%**	**5.60%**	**8.09%**	**49.01%**	**0.01%**
Total O&M Expense	%	**100.00%**	**7.89%**	**6.85%**	**2.26%**	**7.55%**	**8.86%**	**4.63%**	**11.21%**	**36.20%**	**14.55%**
Total Composite Factor for FY 2	**%**	**100.00%**	**8.32%**	**7.02%**	**2.51%**	**7.58%**	**9.99%**	**5.20%**	**8.44%**	**40.75%**	**10.19%**
All Utility Companies	%	100.00%	8.32%	7.02%	2.51%	7.58%	9.99%	5.20%	8.44%	40.75%	10.19%
All Utility 25% to Mid Tex		100.00	14.80%	12.49%	4.46%	13.48%	17.77%	9.25%	15.01%	10.19%	2.55%
Average Number of Customers	%	100.00%	9.62%	7.62%	2.42%	8.18%	9.44%	5.60%	8.10%	49.02%	
LA Division	%	100.00%	0.00%	0.00%	24.90%	75.10%	0.00%	0.00%	0.00%	0.00%	0.00%
Utility No Mid Tex	%	100.00%	16.89%	14.31%	5.13%	15.44%	20.46%	10.61%	17.16%	0.00%	0.00%
Gas Control	%	100.00%	21.28%	18.01%	0.00%	0.00%	25.77%	13.37%	21.57%	0.00%	0.00%

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/06

A. Composite Allocation Factor:		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	MidStates Div	KY Div	MVG	Mid-Tex Div	Atmos P/L Mid Tex	AESI	Atmos P/L & Storage	Atmos Energy Power Systems	Atmos Energy Holdings	Atmos Energy Marketing
Gross Direct PP&E	$	5,439,711,534	398,740,964	354,701,307	152,641,872	376,265,849	627,268,359	288,632,910	323,787,054	1,988,757,546	859,896,947	52,369	49,971,843	3,610,397		15,384,115
Average Number of Customers	#	3,091,479	297,240	235,655	74,661	252,901	291,637	173,204	250,184	1,514,844	336		2	2		813
Total O&M Expense *	$	356,620,544	25,920,364	22,493,532	7,426,747	24,809,531	29,107,323	15,205,659	36,818,964	118,929,678	47,798,914	458,775	1,916,926	1,019,370		24,714,763
(* w/o Allocation)																
Total Composite Factor																
Gross Direct PP&E	%	100.00%	7.32%	6.52%	2.81%	6.92%	11.53%	5.31%	5.95%	36.56%	15.81%	0.00%	0.92%	0.07%	0.00%	0.28%
Average Number of Customers	%	100.00%	9.62%	7.62%	2.42%	8.18%	9.43%	5.60%	8.09%	49.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.03%
Total O&M Expense	%	100.00%	7.27%	6.31%	2.08%	6.96%	8.16%	4.26%	10.32%	33.35%	13.40%	0.13%	0.54%	0.29%	0.00%	6.93%
Total Composite Factor for FY	%	100.00%	8.07%	6.82%	2.44%	7.35%	9.71%	5.06%	8.12%	39.64%	9.74%	0.04%	0.49%	0.12%	0.00%	2.41%

Atmos Energy Corporation
Atmos Energy Mid States Div
Development of Allocation Factors
For Fiscal Year 2007

Div #	Division Name	Sept ' 06 Direct Property Plant & Equipment	Percent of MidStates Property	YE Sept'06 Total O &M w/o 922	Percent of MidStates O & M	YE Sept '06 Avg Number of Customers	Percent of MidStates Customers	**MidStates Allocation Percent**
		(1)	(2)	(3)	(4)	(5)	(6)	**(7)**
70	KIRKSVILLE	7,270,981.92	0.79990	406204.7	1.10369	5,898	1.26882	**1.05747**
72	SE MISSOURI	43,034,064.30	4.73430	2292504.09	6.22889	34,414	7.40340	**6.12220**
92	ILLINOIS	43,536,393.19	4.78957	1,880,061.54	5.10826	22,858	4.91743	**4.93842**
93	TENNESSEE	299,907,053.52	32.99366	8,007,924.70	21.75808	124,423	26.76680	**27.17285**
95	GEORGIA	123,230,080.69	13.55691	5,398,591.16	14.66834	63,746	13.71344	**13.97956**
96	VIRGINIA	55,038,301.37	6.05493	1,739,831.53	4.72724	21,771	4.68347	**5.15521**
97	MISSOURI	34,972,138.73	3.84739	1,289,814.30	3.50451	14,260	3.06774	**3.47321**
98	IOWA	12,727,547.48	1.40020	551,751.90	1.49915	4,267	0.91791	**1.27242**
99	FT. BENNING	634,326.42	0.06978	32,030.65	0.08703	0	0.00000	**0.05227**
09	KENTUCKY	288,632,910.39	31.75336	15,205,659.00	41.31482	173,204	37.26098	**36.77639**
	Total	908,983,798.01	100.00	36,804,373.57	100.00	464,840	100.00	100.00

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Donald S. Roff, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2006-00464, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Affiant further states that he will be present and available for cross examination and for such additional direct examination as may be appropriate at any hearing in Case No. 2006-00464 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his direct testimony in such case.

Donald S. Roff

STATE OF TEXAS
COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Donald S. Roff on this the 19th day of December, 2006.

Ethel Z. Taylor
Notary Public
My Commission Expires: August 13, 2010

NOTARY PUBLIC STATE OF TEXAS
ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 2006-00464**
ATMOS ENERGY CORPORATION KENTUCKY DIVISION	)	

DIRECT TESTIMONY

OF

DONALD S. ROFF

ON BEHALF OF

ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND BUSINESS AFFILIATION.

A. My name is Donald S. Roff and my address is 2832 Gainesborough Drive, Dallas, Texas 75287. I am President of Depreciation Specialty Resources.

Q. WHAT ARE YOUR QUALIFICATIONS AND EXPERIENCE?

A. My qualifications and experience are described on Exhibit DSR-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. A listing of my regulatory appearances is contained on Exhibit DSR-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have conducted a depreciation study of the depreciable natural gas distribution properties in Kentucky (referred to hereinafter as the "Kentucky System") of Atmos Energy Corporation ("Atmos" or "the Company") as of September 30, 2005, and I have made recommendations for revised depreciation rates for inclusion in the Company's revenue requirement. I have also conducted a depreciation study of the plant assets of the Company's Shared Services Unit (SSU)[1] as of September 30, 2006, and I have made recommendation for revised depreciation rates therefore, which rates are utilized by Company witness James C. Cagle for purposes of allocation of common costs to the Company's Kentucky Division. The purpose of my testimony is to present the results of the depreciation studies, describe the depreciation study process and recommend appropriate depreciation rates for use by the Company reflecting depreciation accounting principles and regulatory rules. I will show that my studies produce fair and reasonable levels of depreciation expense utilizing sound accounting practices and principles.

[1] The Company's Shared Services Unit provides common services, such as accounting, legal, risk management, treasury, procurement, information technology, etc., to all of the Company's utility divisions. All of this is more particularly explained in the direct testimony of Company witnesses James C. Cagle and Dan M. Meziere.

Q. DO YOU SPONSOR ANY ADDITIONAL EXHIBITS?

A. Yes. I am sponsoring Exhibit DSR-3 which is the depreciation study prepared for the Company's Kentucky System as of September 30, 2005 (hereinafter referred to as the "Kentucky Depreciation Study"). I am also sponsoring Exhibit DSR-4 which is the depreciation study prepared for the Company's SSU plant as of September 30, 2006 (hereinafter referred to as the "SSU Depreciation Study"). Both the Kentucky Depreciation Study and SSU Depreciation Study include a discussion of depreciation accounting principles, describe the methodology employed for the study, summarize the results of the study and make recommendations relating to depreciation rates and depreciation accounting.

Q. WHY DID YOU PERFORM TWO SEPARATE STUDIES?

A. Separate studies have been performed for the Kentucky System and the Company's SSU plant in order to recognize and accurately capture the fact that the assets which are the subject of each study have different characteristics. The assets which are the subject of the Kentucky Depreciation Study primarily consist of pipe, regulators, meters, facilities, etc. which are typically considered natural gas distribution operations assets that are used to provide natural gas service to end-use customers. The assets which are the subject of the SSU Depreciation Study consist primarily of hardware and software systems which are used by shared services to provide support services to the Company's utility divisions, such as customer support and billing systems, accounting systems, and other such systems which are not replicated at the division level. The preparation of separate studies is also consistent with the manner in which depreciation rates have been established for the Company's utility division plant and SSU plant assets in other rate proceedings.

Q. WERE THE EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. Both the Kentucky Depreciation Study and the SSU Depreciation Study were prepared by me or by persons under my direct supervision.

II. DEPRECIATION STUDY PROCESS

Q. WHAT IS DEPRECIATION?

A. The most widely recognized accounting definition of depreciation is that of the American Institute of Certified Public Accountants, which states:

> *Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.*[2]

Q. WHAT IS THE SIGNIFICANCE OF THIS DEFINITION?

A. This definition of depreciation accounting forms the accounting framework under which both the Kentucky Depreciation Study and SSU Depreciation Study were conducted. Several aspects of this definition are particularly significant, as follows:

- Salvage (net salvage) is to be recognized
- Allocation of costs is over the useful life of the assets
- Grouping of assets is permissible
- Depreciation accounting is a process of cost allocation, not a valuation process
- Cost allocation must be both systematic and rational

Q. WHAT IS MEANT BY THE TERMINOLOGY "SYSTEMATIC AND RATIONAL"?

A. "Systematic" implies the use of a formula. The formula used for calculating the recommended depreciation rates for the Kentucky System is shown on Page 7 of the Kentucky Depreciation Study. This same formula was used for calculating the recommended depreciation rates for the Company's SSU plant and is shown on Page 11 of the SSU Depreciation Study. "Rational" means that the pattern of depreciation (or, in this case, the depreciation rate itself) must match either the pattern of revenues produced by the asset or match the consumption of the asset.

[2] Accounting Research Bulletin No. 43, Chapter 9, Paragraph 5 (June 1953).

Because revenues for the Company's utility operations in Kentucky are determined through regulation and are expected to be so determined in the future, asset consumption must be directly measured and reflected in depreciation rates. The measurement of asset consumption is accomplished by conducting a depreciation study which, as is more fully explained herein below, formulates depreciation rates based upon the mortality characteristics of an asset or group of assets.

Q. ARE THERE OTHER DEFINTIONS OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA)[3], which is the regulatory accounting system prescribed by the Commission[4] and used by the Company for its regulated utility operations in Kentucky, provides a series of definitions related to depreciation and which are shown on Page 5 of the Kentucky Depreciation Study as well as on Page 5 of the SSU Depreciation Study. The depreciation definitions make reference to asset consumption and therefore relate very well to the accounting framework for depreciation. These definitions also form the regulatory framework under which both depreciation Studies were conducted. Under the both Kentucky Depreciation Study and the SSU Depreciation Study, I recommend remaining life rates that provide for full recovery of net investment adjusted for net salvage over the future useful life of each asset category, consistent with the Company's past practices.

Q. HOW ARE DEPRECIATION RATES FORMULATED?

A. Appropriate depreciation rates are formulated through a study of the mortality characteristics of an asset or group of assets including average service life, retirement dispersion defined by Iowa-type curves and net salvage factors.

Q. WHAT IS AVERAGE SERVICE LIFE?

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[3] *See* 18 CFR Part 201 for the USOA applicable to natural gas utilities.
[4] 807 K.A.R. 5:006(3).

A. The average service life of a depreciable asset is the number of years the asset is expected to remain in service. For a group of depreciable assets, it is the estimated service life of the group.

Q. WHAT IS RETIREMENT DISPERSION?

A. Retirement dispersion is the scattering of retirements by age for the individual depreciable assets within a group around the average service life for the entire group of depreciable assets. Standard dispersion patterns are useful and necessary because they make calculations of the remaining life of existing property possible and allow life characteristics to be compared. Iowa-type curves provide a set of standard definitions for retirement dispersion.

Q. PLEASE DESCRIBE THE IOWA-TYPE CURVES.

A. The Iowa-type curves were devised empirically over 60 years ago by the Engineering Research Institute (ERI) at what is now Iowa State University (hence, the namesake). The ERI collected retirement information on many types of industrial and utility property and devised empirical curves that matched the range of retirement patterns found. A total of 18 curves were defined varying from wide to narrow dispersion patterns. There were six left-skewed curves, which are known as the "L series", seven symmetrical curves, which are known as the "S series" and five right-skewed curves, which are known as the "R series". A number identifies the range of dispersion – a low number indicating a wide dispersion pattern and a high number indicating a narrow dispersion pattern. The combination of one letter and one number defines a unique dispersion pattern.

In addition, there is also an "SQ" pattern that has no dispersion and is the equivalent of an amortization period, that is, all assets survive for their entire average life. This pattern has been used for certain general plant accounts.

Q. IN ADDITION TO AVERAGE SERVICE LIFE AND RETIREMENT DISPERSION, YOU MENTIONED PREVIOUSLY THAT NET SALVAGE

FACTORS ANOTHER CATEGORY OF MORTALITY CHARACTERISTICS THAT IS EXAMINED IN DETERMINING APPROPRIATE DEPRECIATION RATES. WHAT IS NET SALVAGE?

A. Net salvage is the difference between gross salvage and cost of removal. If cost of removal exceeds gross salvage, negative net salvage occurs.

Q. IS THERE ANY AUTHORITATIVE REGULATORY SOURCE THAT ADDRESSES THE TOPIC OF NET SALVAGE?

A. Yes. The following quotation directly addresses this topic:

> *Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage, as the name implies, is the difference between the gross salvage that will be obtained when the asset is disposed of and the cost of removing it. Positive net salvage occurs when gross salvage exceeds cost of removal, and negative salvage occurs when cost of removal exceeds gross salvage. Thus the intent of the present concept is to allocate the net cost of an asset to annual accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the thought that ownership of property entails the responsibility for its ultimate abandonment or removal. Hence if current users of the property benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property.*
>
> *This treatment of salvage is in harmony with generally accepted accounting practices and tends to remove from the income statement fluctuations caused by erratic, although necessary, abandonment or uneconomical removal operations. It also has the advantage that current customers pay a fair share, even though estimated, of costs associated with the property devoted to their service.*[5]

Q. WHY IS THIS QUOTATION IMPORTANT?

A. This quotation is important because it addresses several key accounting and ratemaking issues concerning the treatment of net salvage as a component of depreciation. First and foremost, net salvage is an appropriate component of depreciation. Second, inclusion of net salvage in depreciation results in a fair and equitable allocation of cost. Third, from

[5] *Public Utility Depreciation Practices,* NARUC, 1968 Edition, page 24.

a ratemaking perspective, inclusion of net salvage in depreciation expense fulfills the regulatory precept of having customers pay their fair share of costs of the life of the property used to provide service to them. As a result, such treatment is beneficial for both accounting and ratemaking purposes.

Q. DOES THE USOA CONTEMPLATE THE INCLUSION OF NET SALVAGE AS A COMPONENT OF DEPRECIATION?

A. Yes. The USOA instructions clearly intend net salvage to be a component of depreciation as it must be charged to Account 108, Accumulated Provision for Depreciation.[6]

Q. THUS FAR YOU HAVE DESCRIBED THE MORTALITY CHARACTERISTICS WHICH ARE EVALUATED IN CONNECTION WITH PERFORMING A DEPRECIATION STUDY. CAN YOU DESCRIBE THE DEPRECIATON STUDY PROCESS ITSELF?

A. Certainly. A depreciation study consists of four distinct yet interrelated phases – data collection, analysis, evaluation and calculation. Each of these phases occurred in connection with preparing both the Kentucky Depreciation Study and the SSU Depreciation Study. Data collection refers to the gathering of historical investment activity data that was provided by the Company. After the data was assembled, I or persons under my direction performed two separate analyses[7] - one analysis for the determination of life and another one for the determination of the net salvage percentage for the different asset groups being studied (each analysis is more fully discussed later herein).

Once the analysis phase was completed, the evaluation phase was then conducted which entailed the development of an understanding of asset history and its applicability to the surviving asset base into the future. This phase also gave consideration to the changing asset base and the

[6] 18 CFR Part 201, Gas Plant Instruction 10.F provides "the book cost less net salvage of depreciable gas plant retired shall be charged in its entirety to account 108, Accumulated Provision for Depreciation of Gas Plant in Service".

[7] Analysis refers to the statistical processing of the data gathered in the first phase of the study process.

Company's plans and expectations. I conducted the evaluation phase with the assistance and input from Company personnel.

The last phase of each depreciation study was the calculation phase and was performed by me or my firm's employees under my direct supervision. This phase utilized the information and results determined in the first three phases of the depreciation study process in the computation of recommended depreciation rates.

Q. DURING THE ANALYSIS PHASE, YOU INDICATED THAT TWO ANALYSES, LIFE ANALYSIS AND NET SALVAGE, WERE PERFORMED. WHAT DID THE LIFE ANALYSIS ENTAIL?

A. For some categories of production, storage, transmission, distribution and general plant, the age of both surviving and retired property is known and an actuarial analysis was utilized for these property groups. The actuarial[8] analysis process is more particularly described on pp. 8-10 of the Kentucky Depreciation Study and on pp. 8-10 of the SSU Depreciation Study. For those asset categories for which the age of retirements is not known, a simulation[9] analysis was utilized. The simulated analysis technique is more particularly described on p. 10 of the Kentucky Depreciation Study.

Q. AFTER THE LIFE ANALYSIS WAS PERFORMED, WHAT ACTIONS WERE UNDERTAKEN IN CONNECTION THEREWITH DURING THE EVALUATION PHASE?

A. Summaries of the individual asset category life analysis indications were prepared and discussed with Company personnel. Anomalies and trends were identified and input from the Company's engineering and operations personnel was requested and obtained where necessary. The types of assets surviving and retiring were also discussed. A single average service life and Iowa-type curve was then selected for each asset category best reflecting the combination of the historical results and the additional

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[8] Technically referred to as the Actuarial Method of Life Analysis.

[9] Technically referred to as the Simulated Plant Record Method.

information obtained from and during discussions with the Company's engineering, operations and accounting personnel.

Q. HOW WERE NET SALVAGE PERCENTAGES DETERMINED?

A. As I stated previously, determination of net salvage percentages is performed as part of the second phase of the preparation of a depreciation study. This entails the determination of both salvage and cost of removal. In connection with this, annual salvage amounts, cost of removal and retirements were provided by the Company by account for the period of 1991 through September 30, 2005 for the Kentucky Depreciation Study and the for the period of 1993 through 2006 for the SSU Depreciation Study.

Q. AFTER PERFORMING THE NET SALVAGE ANALYSIS, WHAT ACTIONS WERE UNDERTAKEN IN CONNECTION THEREWITH DURING THE EVALUATION PHASE?

A. As with the life analysis, discussions were held with applicable Company personnel to the extent necessary to examine salvage cost, cost of removal, cost of retirements and the Company's present and future plans associated with retirement and removal of depreciable assets.

Q. WHAT ACTIONS WERE PERFORMED AS PART OF THE FINAL PHASE OF THE PREPARATION OF THE DEPRECIATION STUDIES?

A. In the calculation phase, annual salvage, cost of removal and net salvage percentages were then calculated for purposes of each study by dividing the annual salvage, cost of removal and net salvage amounts by the retirement amounts applicable to the asset groups subject of each depreciation study.

Q. WHAT OCCURRED AFTER THE PERFORMANCE OF EACH PHASE OF BOTH DEPRECIATION STUDIES YOU HAVE DISCUSSED?

A. Both studies were formalized into written reports and presented to the Company. The formalized written reports are the Kentucky Depreciation Study and the SSU Depreciation Study attached to my testimony as Exhibit DSR-3 and Exhibit DSR-4, respectively.

Q. IS THE PROCESS YOU HAVE DESCRIBED IN YOUR TESTIMONY FOR PERFORMANCE AND REPARATION OF THE DEPRECIATION STUDIES RECOGNIZED FOR BOTH REGULATORY RATEMAKING AND ACCOUNTING PURPOSES AS THE ACCEPTED PROCESS FOR DETERMINING REASONABLE DEPRECIATION RATES FOR THE ASSETS SUBJECT OF THE STUDIES?

A. Yes.

III. THE KENTUCKY DEPRECIATION STUDY RESULTS

Q. DID YOU PERFORM AND PREPARE THE KENTUCKY DEPRECIATION STUDY IN ACCORDANCE WITH THE PROCESS THAT YOU HAVE DESCRIBED IN YOUR TESTIMONY?

A. Yes.

Q. IS THIS THE STUDY UPON WHICH THE COMPANY RELIES IN THIS CASE TO ESTABLISH DEPRECIATION RATES FOR ITS KENTUCKY SYSTEM?

A. Yes. In this docket, Atmos is relying on the Kentucky Depreciation Study that I prepared for its Kentucky System. As stated previously, the Kentucky System consists of the Company's net plant in service in Kentucky used to provide natural gas service to its customers, which includes physical plant, property and equipment. For purposes of the Depreciation Study, the net plant comprising the Kentucky System is categorized according to function – production, storage, transmission, distribution and general plant.

Q. WHAT WERE YOUR FINDINGS AND RECOMMENDATIONS?

A. I found that changes were needed to the mortality characteristics for every asset category resulting in revised depreciation rates. A summary comparison of the existing depreciation rates and those recommended in the Kentucky Depreciation Study by asset functional category is as follows:

Function	Existing	Recommended
	%	%
Production	0.00	3.37
Storage	1.58	1.81
Transmission	1.37	1.80
Distribution	3.92	3.95
General	8.90	8.52
Total Gas Plant	3.93	3.97

Q. HAVE YOU QUANTIFIED THE IMPACT ON ANNUAL DEPRECIATION EXPENSE DUE TO YOUR RECOMMENDED CHANGES?

A. Yes. The above summary was taken from Schedule 1 of Exhibit DSR-3. Using September 30, 2005, depreciable balances, the effect of the recommended depreciation rates on annual depreciation expense is an increase of approximately $126,000.

Q. WHAT ARE THE PRIMARY FORCES THAT ARE DRIVING THE RECOMMENDED CHANGE IN ANNUAL DEPRECIATION EXPENSE?

A. The change in annual depreciation expense is affected by three separate factors – changes in average service life, changes in net salvage and the effect of reserve position. Based upon the magnitude and direction of the change in depreciation rates and annual depreciation expense, average service lives have increased thereby producing lower annual depreciation expense. This decrease, however, is offset by negative net salvage.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING PRODUCTION PLANT.

A. During the performance of the Kentucky Depreciation Study, we found that this functional group of assets, consisting primarily of rights-of-way and purification equipment, had not been depreciated in the past. The composite depreciation rate increases from 0.00% to 3.37%. The annual depreciation expense impact is $4,383.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING STORAGE PLANT.

A. For the Storage Plant functional group, the composite depreciation rate increases from 1.58% to 1.81%. The increase is due to the inclusion of cushion gas[10] in the depreciable rate base. The annual depreciation expense impact is $11,830.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING TRANSMISSION PLANT.

A. For the Transmission Plant functional group, the depreciation rate increases from 1.37% to 1.80%. Although the depreciation rate actually decreased as a result of longer average service lives, the decrease is more than offset by negative net salvage for Account 367, Mains. The net dollar impact of the change in the depreciation rate is an increase in annual depreciation expense of approximately $112,000.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING DISTRIBUTION PLANT.

A. For the Distribution Plant functional group, the depreciation rate increases slightly from 3.92% to 3.95% as a result in changes to both average service lives and net salvage factors. The impact on annual depreciation expense is an increase of approximately $55,000 due to the weighting of individual account amounts.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING GENERAL PLANT.

A. The composite depreciation rate for the General Plant functional group has decreased from 8.90% to 8.52% because average service lives for assets within the group have both shortened and lengthened. The impact of the change in the depreciation rate is a decrease in annual depreciation expense by approximately $60,000.

[10] Cushion gas is that level of natural gas consistently maintained within an underground storage reservoir to ensure the operational integrity of the reservoir. The appropriate level of cushion gas is determined by the Company's engineering and operations personnel.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE FOR THE TOTAL COMPANY.

A. At the Total Company depreciable level, the composite depreciation rate increases from 3.93% to 3.97%, or approximately $124,000 more in depreciation expense on an annual basis.

Q. DO YOU HAVE ANY RECOMMENDATIONS AS A RESULT OF THE KENTUCKY DEPRECIATION STUDY?

A. Yes. I recommend that the Commission approve and the Company adopt the depreciation rates shown on Schedule 1 of the Kentucky Depreciation Study.

Q. UPON WHAT TO YOU BASE THIS RECOMMENDATION?

A. I base this recommendation on the fact that I have conducted a comprehensive depreciation study, giving appropriate recognition to historical experience, recent trends and Company expectations. The Kentucky Depreciation Study results in a fair and reasonable level of depreciation expense which, when incorporated into a revenue stream, will provide the Company with adequate capital recovery until such time as a new depreciation study indicates a need for change.

IV. THE SSU DEPRECIATION STUDY RESULTS

Q. DID YOU PERFORM AND PREPARE THE SSU DEPRECIATION STUDY IN ACCORDANCE WITH THE PROCESS THAT YOU HAVE DESCRIBED IN YOUR TESTIMONY?

A. Yes.

Q. IS THIS THE STUDY UPON WHICH THE COMPANY RELIES IN THIS CASE TO ESTABLISH DEPRECIATION RATES FOR SSU PLANT?

A. Yes. In this docket, Atmos is relying on the SSU Depreciation Study that I prepared for its SSU plant as part of allocated common costs more particularly described in the direct testimony of Company witnesses

James C. Cagle and Dan M. Meziere.[11] As stated previously, the SSU general plant consists primarily of software and hardware systems which are used in connection with the provision of common services to the Company's utility divisions. For purposes of the SSU Depreciation Study, the net plant comprising the SSU general plant is categorized according to function.

Q. WHAT WERE YOUR FINDINGS AND RECOMMENDATIONS?

A. I found that changes were needed to the mortality characteristics for every asset category resulting in revised depreciation rates. A summary comparison of the existing depreciation rates and those recommended in the SSU Depreciation Study by asset functional category is as follows:

	Existing Rate %	SSU Study Rate %
General Plant	9.09	10.32

Q. HAVE THE SSU DEPRECIATION RATES THAT RESULT FROM YOUR SSU DEPRECIATION STUDY BEEN ADOPTED BY OTHER STATE REGULATORY COMMISSION'S FOR ATMOS' USE?

A. No, because the SSU Depreciation Study is so new, this is the first rate case in which it has been introduced by the Company. However, based upon a similar study which I performed in 2002, Atmos has had SSU depreciation rates approved in several jurisdictions, including Louisiana, Texas and Virginia.

Q. WOULD YOU SUMMARIZE THE RESULTS OF THE SSU DEPRECIATION STUDY?

[11] As more particularly described in the direct testimony of Mr. Cagle, a portion of depreciation expense on SSU general plant, calculated at the depreciation rates proposed in the SSU Depreciation Study, is allocated to the Kentucky Division as part of O&M expense included in the Company's revenue requirement in this rate filing. The SSU Depreciation Study does not address the Company's allocations of plant and expense, only depreciation rates for SSU general plant.

A. Yes. In general, average service lives have increased. Net salvage remained the same for each asset category. There are three asset categories to contain the largest changes in annual depreciation expense: Account 399.01, Server Hardware; Account 399.08, Application Software and Account 399.24, General Start-up Costs. For Account 399.01, the decrease in annual depreciation expense of $1,069,241 is due to an increase in average service life from 5 years to 10 years. For Account 399.08, the increase in annual depreciation expense of $3,217,244 is due to reserve position. For Account 399.24, the increase in annual depreciation expense of $1,751,828 is due to reserve position.

Q. WHEN YOU USE THE TERM "RESERVE POSITION", WHAT DO YOU MEAN?

A. The term "reserve position" refers to the difference between a theoretical reserve and the existing book reserve. If the theoretical reserve is greater than the book reserve, past depreciation has been inadequate compared to the depreciation parameters developed in the SSU study, and an upward adjustment to the depreciation rate is required. If the opposite is true, a downward adjustment to the depreciation rate is required.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE DEPRECIATION RATES THAT SHOULD BE ESTABLISHED FOR SSU IN THIS CASE.

A. I recommend that the Commission adopt the depreciation rates shown on Schedule 1 of Exhibit DSR-4. I base this recommendation on the fact that I have conducted a comprehensive depreciation study, giving appropriate recognition to historical experience, recent trends and Company expectations. My study results in a fair and reasonable level of depreciation expense which, when incorporated into a revenue stream, will provide the Company with adequate capital recovery until such time as a new depreciation study indicates a need for change.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

EXHIBIT DSR-1

Academic Background

Donald S. Roff graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Management Engineering in 1972.

Mr. Roff has also received specialized training in the area of depreciation from Western Michigan University's Institute of Technological Studies. This training involved three forty-hour seminars on depreciation entitled "Fundamentals of Depreciation", "Fundamentals of Service Life Forecasting" and "Making a Depreciation Study" and included such topics as accounting for depreciation, estimating service life, and estimating salvage and cost of removal.

Employment and Professional Experience

Following graduation, Mr. Roff was employed for eleven and one-half years by Gilbert Associates, Inc., as an engineer in the Management Consulting Division. In this capacity, he held positions of increasing responsibility related to the conduct and preparation of various capital recovery and valuation assignments.

In 1984, Mr. Roff was employed by Ernst & Whinney and was involved in several depreciation rate studies and utility consulting assignments.

In 1985, Mr. Roff joined Deloitte Haskins & Sells (DH&S), which, in 1989, merged with Touche Ross & Co. to form Deloitte & Touche. In 1995, Mr. Roff was appointed as a Director with Deloitte & Touche.

In November, 2005, Mr. Roff formed Depreciation Specialty Resources to serve the utility industry.

During his tenure with Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has participated in or directed depreciation studies for electric, gas, water and steam heat utilities, pipelines, railroad and telecommunication companies in over 30 states, several Canadian provinces and Puerto Rico. This work requires an in-depth knowledge of depreciation accounting and regulatory principles, mortality analysis techniques and financial practices. At these firms, Mr. Roff has had varying degrees of responsibility for valuation studies, development of depreciation accrual rates, consultation on the unitization of property records, and other studies concerned with the inspection and appraisals of utility property, preparation of rate case testimony and support exhibits, data responses and rebuttal testimony, in addition to appearing as an expert witness.

Industry and Technical Affiliations

Mr. Roff is a registered Professional Engineer in Pennsylvania (by examination).

Mr. Roff is a member of the Society of Depreciation Professionals and a Certified Depreciation Professional, and a Technical Associate of the American Gas Association (A.G.A.) Depreciation Committee. He currently serves as the lead instructor for the A.G.A.'s Principles of Depreciation Course.

EXHIBIT DSR-2

DONALD S. ROFF

TESTIMONY EXPERIENCE

CASE NO.	DATE	COMPANY	JURISDICTION	SUBJECT
Docket No. 93-3005	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 93-3025	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 12820	June 1994	Central Power and Light Company	Texas	Electric Depreciation Rates
Case No. U-10380	Dec 1994	Consumers Power Company	Michigan	Gas Depreciation Rates and Accounting
Cause No. 39938	April 1995	Indianapolis Power & Light Company	Indiana	Electric Depreciation Rates
Case No. U-10754	July 1995	Consumers Power Company	Michigan	Electric Depreciation Rates and Accounting
Docket No. 13369	Aug 1995	West Texas Utilities Company	Texas	Electric Depreciation Rates
Docket No. 95-02116	Sept 1995	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Docket No. 95-715-G	Oct 1995	Piedmont Natural Gas Company	South Carolina	Gas Depreciation Rates
Docket No. 14965	Dec 1995	Central Power and Light Company	Texas	Electric Depreciation Rates
Cause No. 40395 (I)	Feb 1996	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
GUD NO. 8664	Oct 1996	Lone Star Pipeline Company	Texas	Gas Depreciation Rates
Docket No. 96-360-U	Nov 1996	Entergy Arkansas Inc.	Arkansas	Electric Depreciation Rates
Docket No. 16705	Nov 1996	Entergy Gulf States Inc.	Texas	Electric Depreciation Rates/Competitive Issues
Docket No. ER-97-394	Mar 1997	Missouri Public Service	Missouri	Electric Depreciation Rates/Competitive Issues
Docket No. U-22092	Mar 1997	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates/Competitive Issues
Docket No. 97-00982	May 1997	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Cause No. 40395 (II)	June 1997	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11509	Sept 1997	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. ER98-11	Sept 1997	Long Island Lighting Company	FERC	Electric Depreciation Rates
Docket No. 8390-U	Dec 1997	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Cause No. 41118	Mar 1998	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11722	Oct 1998	Detroit Edison Company	Michigan	Electric Depreciation Rates
Docket No. 98-2035-03	Nov 1998	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 99-4006	April 1999	Nevada Power Company	Nevada	Electric Depreciation Rates
GUD Docket No. 9030	March 2000	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting
GUD Docket No. 9145	April 2000	TXU Gas Distribution	Texas	Gas Depreciation Rates
City of Tyler	Dec 2000	Reliant Energy Entex	Texas	Gas Depreciation Rates and Accounting
Docket No. U-24993	March 2001	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates and Accounting
Docket Nos. GR01050328/GR0105029	May 2001	Public Service Electric & Gas	New Jersey	Gas Depreciation Rates and Accounting
Case No. U-12999	July 2001	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. 01-10002	Oct 2001	Nevada Power Company	Nevada	Electric Depreciation Rates
Docket No. 14618-U	Nov 2001	Savannah Electric and Power Company	Georgia	Electric Depreciation Rates
Docket No. 01-11031	Dec 2001	Sierra Pacific Power Company	Nevada	Electric Depreciation Rates
Docket No. 010949-EL	Jan 2002	Gulf Power Company	Florida	Electric Depreciation Rates
Docket No. 14311-U	Jan 2002	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. UD-00-2	March 2002	Entergy New Orleans, Inc.	New Orleans	Electric Depreciation Accounting
Cause No. PUD200200166	May 2002	Reliant Energy Entex	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 01-243-U	June 2002	Reliant Energy Entex	Arkansas	Gas Depreciation Rates and Accounting
Docket No. 02-035-12	Oct 2002	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 20000-ER-2-192	Oct 2002	PacifiCorp	Wyoming	Electric Depreciation Rates
Docket No. UE-021271	Oct 2002	PacifiCorp	Washington	Electric Depreciation Rates
Docket No. UM-1064	Oct 2002	PacifiCorp	Oregon	Electric Depreciation Rates
Docket No. PAC-E-02-5	Oct 2002	PacifiCorp	Idaho	Electric Depreciation Rates
Docket No. 02-0391	Oct 2002	Hawaiian Electric Company, Inc.	Hawaii	Electric Depreciation Rates and Accounting
Docket No. 03-ATMG-1036-RTS	June 2003	Atmos Energy Corporation	Kansas	Gas Depreciation Rates and Accounting
Docket No. 02-0391	Aug 2003	Hawaiian Electric Company, Inc.	Hawaii	Electric Depreciation Rates and Accounting
Cause No. 42458	Sept 2003	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates and Accounting
Docket No. 03-ATMG-1036-RTS	Nov 2003	Atmos Energy Corporation	Kansas	Gas Depreciation Rates and Accounting
Case No. 12999	Dec 2003	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Case No. 12999	Feb 2004	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. ER-2004-0570	Apr 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Docket No. 04-100-U	Apr 2004	The Empire District Electric Company	Arkansas	Electric Depreciation Rates and Accounting
Docket No. PUE 2003-00597	Aug 2004	Atmos Energy Corporation	Virginia	Gas Depreciation Rates and Accounting
Docket No. 18638-U	Oct 2004	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. ER-2004-0570	Nov 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Docket No. ER-2004-0570	Nov 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Cause No. 200400610	Jan 2005	Oklahoma Natural Gas Company	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 18638-U	March 2005	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. 20298	May 2005	Atmos Energy Corporation	Georgia	Gas Depreciation Rates and Accounting
Cause No. 200400610	June 2005	Oklahoma Natural Gas Company	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 20298	Oct 2005	Atmos Energy Corporation	Georgia	Gas Depreciation Rates and Accounting
Case No. GR-2006-0387	Apr 2006	Atmos Energy Corporation	Missouri	Gas Depreciation Rates and Accounting
Docket No. 05-00258	July 2006	Atmos Energy Corporation	Tennessee	Gas Depreciation Rates and Accounting
Docket No. 06S-234EG	Sept 2006	Public Service Company of Colorado	Colorado	Electric Depreciation Rates and Accounting
Docket No. GUD No. 9676	Oct-06	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting

EXHIBIT DSR-3

Depreciation Specialty Resources

Atmos Energy Corporation

Book Depreciation Study of Atmos Energy Corporation Kentucky Properties As of September 30, 2005

2832 Gainesborough Drive, Dallas, TX 75287-3483 469-964-9090

Atmos Energy Corporation

Book Depreciation Study of Atmos Energy Corporation Kentucky Properties As of September 30, 2005

November 2006

Atmos Energy Corporation
Three Lincoln Center
5430 LBJ Freeway
Dallas, TX 75240

Attention: Mr. Thomas Petersen

In accordance with your request and with the cooperation and participation of your staff, a book depreciation study of Atmos Energy Corporation's Kentucky properties ("Atmos" or "the Company") has been conducted. The study covered all depreciable and amortizable property and recognized addition and retirement experience through September 30, 2005. The purpose of the study was to determine if the existing depreciation rates remain appropriate for the property and, if not, to recommend changes. Changes were found to be needed and are recommended. The changes in aggregate cause an increase in depreciation rates used to calculate the annual depreciation expense.

A comparison of the effect of the existing rates and the recommended rates is shown below, based on depreciable plant balances as of September 30, 2005:

Function	Composite Depreciation Rate	
	Existing %	Recommended %
Production	0.00	3.37
Storage	1.58	1.81
Transmission	1.37	1.80
Distribution	3.92	3.95
General	8.90	8.52
Total	3.93	3.97

The summary above is taken from Schedule 1, which shows the annual depreciation amounts calculated from the existing rates and the recommended account rates and the differences. Based upon the September 30, 2005 depreciable balances, the recommended depreciation rates will result in an annual increase in depreciation provisions of $123,599 or 1.1%. The study results are being driven by an increase in depreciation rates for every functional asset category, except General Plant.

Schedule 2 shows the mortality characteristics used to calculate the recommended depreciation rates. The recommended depreciation rates are straight-line over life measured by time using the equal life group (ELG) procedure and the remaining life technique, consistent with the existing, approved rates.

The following sections of this report describe the methods of analysis used and the bases for the conclusions reached. The remainder of the report will present the results and recommendations for both immediate and future actions by the Company.

We appreciate this opportunity to serve Atmos Energy Corporation and would be pleased to meet with you to discuss further the matters presented in this report, if you desire.

Yours truly,

Donald S. Roff

President

Depreciation Specialty Resources

PURPOSE OF DEPRECIATION

Book depreciation accounting is the process of recognizing in financial statements the consumption of physical assets in the process of providing a service or a product. Generally accepted accounting principles require the recording of depreciation to be systematic and rational. To be systematic and rational, depreciation should, to the extent possible, match either the consumption of the facilities or the revenues generated by the facilities. Accounting theory requires the matching of expenses with either consumption or revenues to ensure that financial statements reflect the results of operations and changes in financial position as accurately as possible. The matching principle is often referred to as the "cause and effect" principle; thus, both the cause and the effect are required to be recognized for financial accounting purposes. This study was conducted in a manner consistent with the matching principle of accounting.

Because utility revenues are determined through regulation, and this study assumes that such regulation will continue, asset consumption is not automatically in revenues. Therefore, the consumption of utility assets must be measured directly by conducting a book depreciation study to accurately determine the mortality characteristics of the assets.

Matching is also an essential element of basic regulatory philosophy, and it has become known as "intergenerational customer equity". Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that the charges to customers reflect the actual costs of providing service.

DEPRECIATION DEFINTIONS

The Uniform System of Accounts ("USOA") prescribed for gas utilities by the Federal Energy Regulatory Commission ("FERC") followed by Atmos states that:

> "Depreciation", as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and in the case of natural gas companies, the exhaustion of natural resources.
>
> "Service value" means the difference between original cost and net salvage value of gas plant.
>
> "Net salvage value" means the salvage value of property retired less the cost of removal.
>
> "Salvage value" means the amount received for the property retired, less any expenses incurred in connection with the sale or in preparing the property for sale or, if retained, the amount at which the material is chargeable to materials and supplies, or other appropriate account.
>
> "Cost of removal" means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto.

As is clear from the wording of the salvage value and the cost of removal definitions, it is the salvage that will actually be received and the cost of removal that will actually be incurred, both measured at the price level at the time of receipt or incurrence that is required to be recognized in the depreciation rates of Atmos.

These definitions are consistent with the purpose of depreciation, and the study reported here was conducted in a manner consistent with both.

ACCOMPLISHMENT OF ACCOUNTING AND REGULATORY PRINCIPLES

Utility depreciation accounting is a group concept. Inherent in this concept is the assumption that all property is fully depreciated at the time of retirement, regardless of age, and there is no attempt to record the depreciation applicable to individual components of the groups. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property group is "average". The group carries with it recognition that most property will be retired at an age less than or greater than the average service life. This study recognized the existence of this variation through the identification of Iowa-type retirement dispersions.

The study required to determine the applicable mortality characteristics is independent from the calculation of depreciation rates. The resulting mortality characteristics can be used to calculate either Average Life Group ("ALG") or Equal Life Group ("ELG") rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG. ALG and ELG are straight-line over life measured by time, with ALG utilizing average life and ELG utilizing actual life. For ALG, all property in the group is assumed to have a life equal to the average life. ELG recognizes that, in reality, only a small portion of the group retires at an age equal to the average service life. For the average to exist, about half the investment in an asset group will be retired at ages less than average life, a small amount at average life, and the rest at ages greater than average life. It is the use of this dispersion in the rate calculation that causes ELG rates to better match cost recovery with the use and benefit of the property. Thus, the ELG procedure best accomplishes the purpose of book depreciation accounting by ensuring the recording of depreciation provision match the actual consumption of physical assets. Since ELG matches the recording of consumption with actual consumption, customers will pay the actual cost incurred to serve them. The ELG procedure is recommended, consistent with the existing, approved rates. A detailed discussion of the ELG procedure is included in the Appendix A to this report.

THE BOOK DEPRECIATION STUDY

Implementation of a policy toward book depreciation that recognizes the purpose of depreciation accounting requires the determination of the mortality characteristics that are applicable to the surviving property. One purpose of the depreciation study reported here was to accurately measure those mortality characteristics and to use those characteristics to determine appropriate rates for the accrual of depreciation expenses.

The major effort of the study was the determination of the appropriate mortality characteristics. The remainder of this report describes how those characteristics were determined, describes how the mortality characteristics were used to calculate the recommended depreciation rates, and presents the results of the rate calculations.

The typical study consists of the following steps:

> Step One is a Life Analysis consisting of the determination of historical experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Two is a Salvage and Cost of Removal Analysis consisting of a study of salvage and cost of removal experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Three consists of the determination of average service lives, retirement dispersion patterns identified by Iowa-type curves and the net salvage factors applicable to the surviving property.
>
> Step Four is the determination of the depreciation rate applicable to each depreciable property group recognizing the results of the work in Steps One through Three, and a comparison with the existing depreciation rates.

LIFE ANALYSIS

The Life Analysis for the property concerns the determination of average service lives ("ASL") and Iowa-type dispersion patterns. An evaluation of investment experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of average service lives and retirement dispersions.

An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving plant, formed the basis for the determination of average service lives and retirement dispersion patterns for all property groups. For most accounts, retirement experience from transaction years 1973 through 2005 was analyzed using the Actuarial Method of Life Analysis. This method could be used because aged data are available for certain asset categories.

The actuarial method determines actual survivor curves (observed life tables) for selected periods of actual retirement experience. In order to recognize trends in life characteristics and to ensure that the valuable information in the curves is available to the analyst, observed life tables were calculated and plotted by computer, using several different periods of retirement experience. The average service lives and retirement dispersion patterns indicated by the actual survivor curves were identified by visually fitting Iowa-type dispersion curves to the actual curves. Retirement dispersion refers to the pattern of retirements as a function of age over the life of each property group. For each asset category, an Iowa-type curve combined with an estimated average service life was selected. This selection was based upon an analysis of historical investment activity, associated mortality trends and the types of assets surviving and retiring. The workpapers prepared as an integral part of the depreciation study contain the rationale for each selection.

Trends in historical mortality experience are helpful in understanding history. In order to determine trends, the periods (year bands) of retirement experience analyzed were the past five years, the past ten years, the past fifteen years, the past twenty years and the full band of band of retirement experience. The observed life tables and the Iowa curves fitted to each of these year bands were plotted. This visual approach ensures that the data contained in the observed life tables are available to the analyst and that the analyst does not allow the computer calculations to be the sole determinant of study results.

Where the age of retirement was not known, the Simulated Plant Record ("SPR") Method of life analysis was utilized. The SPR method determines retirement dispersion and average service life combinations for various bands of years which best match the actual retirements and balances for each asset category. The simulated balances procedure consists of applying survivor ratios (portion surviving at each age) from Iowa-type dispersion patterns in order to calculate annual balances, and then comparing the calculated balances with the actual balances for several periods, followed by statistical comparisons of differences in balances. The simulated retirements procedure is similar, except that the retirement frequency rates of the Iowa patterns are utilized to calculate annual retirements, and the comparisons are to actual retirements rather than to balances. Tabulations of the best ranking curves were made and this became the starting point for the evaluation phase of my review. In most cases, retirement history for a forty-year period was available.

For accounts having little experience or having retirement experience that is not an adequate measure of the expected mortality characteristics of surviving property, evaluation of the significance of history played a major role in selecting the mortality characteristics shown on Schedule 2.

SALVAGE AND COST OF REMOVAL ANALYSIS

Salvage and cost of removal experience was analyzed using experience from the period 1996 – 2005. Rolling and shrinking bands were analyzed to help expose trends. An evaluation of salvage and cost of removal experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of salvage and cost of removal factors.

The analysis consisted of calculating salvage and cost of removal factors by relating the recorded salvage and cost of removal for each property group to the retirements that caused the salvage and cost of removal to occur.

EVALUATION OF ACTUAL EXPERIENCE

The typical evaluation consists of Life Analysis and Salvage and Cost of Removal Analysis, which involve the measurement of what has occurred in the past. History is sometimes a misleading indicator of the future. There are many kinds of events that can cause history to be misleading, among them significant changes contemplated in the underlying accounting procedures and/or changes in other management practices, such as maintenance procedures. It is the evaluation phase of a depreciation study that identifies if history is a good indicator of the future. Blind acceptance of history often results in selecting mortality characteristics to use for calculating depreciation rates that will provide recovery over a time period longer than productive life.

For each property group, the typical analysis processes involve only historical investment experience. Since depreciation rates will be applied to surviving property, the historical mortality experience indicated by a Life Analysis and the Salvage and Cost of Removal Analysis is evaluated to ensure that the mortality characteristics used to calculate the depreciation rates are applicable to the surviving property. The evaluation is required to ensure the validity of the depreciation rates.

The normal evaluation process requires knowledge of the type of property surviving; the type of property retired; the reasons for changing life, dispersion, salvage and cost of removal; and the effect of present and future Atmos plans on the property mortality characteristics.

CALCULATION OF DEPRECIATION RATES

A straight-line remaining life rate for each depreciable property group was calculated using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance} - \text{Future Net Salvage} - \text{Book Reserve}}{\text{Average Remaining Life}}$$

Formula numerator elements in percent of depreciable plant balance and the denominator in years produce a rate in percent. This formula illustrates that a remaining life rate recognizes the book reserve position. The depreciable balances and book reserves were taken from accounting records, and the net salvage factors were determined by the study.

The remaining lives for each property group are a function of the age distribution of surviving plant and the selected average service life and retirement dispersion.

RESULTS

A comparison of the existing depreciation rates to the proposed study depreciation rates can be found on Schedule 1 in this report. A listing, by account, of the existing and the proposed mortality characteristics can be found on Schedule 2 in this report.

Production Plant

The accounts in this functional category have not been depreciated in the past. The recommended depreciation rate is 3.37%. The increase in annual depreciation expense is $4,383.

Storage Plant

The depreciation rate for this functional category decreases from 1.58% to 1.81%. The lives are slightly longer and less negative net salvage is recognized. The increase in annual depreciation expense is $11,830.

Transmission Plant

The depreciation rate for this functional category increased from 1.37% to 1.80%. Longer lives were offset by negative net salvage. The major investment in this functional category is Account 367, Mains. An average service life of 55 years was selected with an R1 Iowa curve. Net salvage is estimated to be negative 25%. The increase in annual depreciation expense is $112,284

Distribution Plant

For this asset grouping, an increase in the depreciation rate is indicated from 3.92% to 3.95%. Longer lives were offset by negative net salvage. Two accounts comprise the majority of the change in annual depreciation expense, Account 376, Mains and Account 380, Services. An average service life of 55 years with an R0.5 dispersion, was selected for Account 376. The net salvage allowance is negative 25%. For Account 380, the average service life is 40 years with an R1.5 curve. Net salvage is negative 75%. The increase in annual depreciation is $55,311.

General Plant

There is a decrease in depreciation rate indicated for this asset category from 8.90% to 8.52%. Average service life changes are in both directions. The single largest change in annual depreciation expense is for Account 399.06, OTP – PC Hardware. The recommended average service life is 10 years with an L1 curve. Net salvage is estimated to be positive 2%. The annual depreciation expense decrease is $60,208, and is primarily due to reserve position.

RESERVE COMPARISON

Because remaining life rates are recommended (consistent with the existing rates), a comparison of the accumulated provision for depreciation with the calculated theoretical reserve at September 30, 2005, is not meaningful, and no comparison is presented. This is because the only way a reserve difference can exist is through the use of whole life rates.

RECOMMENDATIONS

Our recommendations for your future action in regard to book depreciation are as follows:

1. The depreciation rates shown in Column 6 of Schedule 1 are applicable to existing property and are recommended for implementation at such time as their effect can be incorporated into service rates.

2. Because of variation of life and net salvage experience with time, a depreciation study should be made during 2010 based upon retirement experience through September 30, 2009. Exact timing of the study should be coordinated with a retail rate case to ensure timely implementation of revised depreciation rates.

3. We recommend that Atmos consider the utilization of a vintage amortization accounting process. This approach has been implemented by numerous utilities all over the country. This approach solves the universal problem of unreported retirements, is intended to simplify the property accounting effort, and provides a better matching of the accounting effort with the magnitude of the asset base.

4. For new asset categories that arise in the future for which no depreciation rate is currently approved, or for asset categories that are presently fully depreciated and may have new assets added in the future, we recommend that the functional composite depreciation rates be used until future depreciation studies are conducted. The functional composite depreciation rates are as follows:

Production Plant	3.37%
Storage Plant	1.81%
Transmission Plant	1.80%
Distribution Plant	3.95%
General Plant	8.52%

ATMOS ENERGY CORPORATION - KENTUCKY **SCHEDULE 1**

Book Depreciation Study as of September 30, 2005

Comparison of Depreciation Rates and Annual Amounts

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Account	Description	9/30/2005 Balance	Existing Rate	Annual Amount	Study Rate	Annual Amount	Increase or (Decrease)
		$	%	$	%	$	$
	PRODUCTION PLANT						
325.20	Producing Leaseholds	2,353	0.00	0	5.89	139	139
325.40	Rights-of-Way	83,422	0.00	0	2.29	1,910	1,910
336.00	Purification Equipment	44,369	0.00	0	5.26	2,334	2,334
	Total Production Plant	130,144	0.00	0	3.37	4,383	4,383
	STORAGE PLANT						
351.00	Structures and Improvements	309,065	1.93	5,965	0.60	1,854	(4,111)
352.00	Well Construction and Equipment	2,176,341	2.71	58,979	2.11	45,921	(13,058)
352.03	Cushion Gas	1,694,833	0.00	0	2.38	40,337	40,337
352.11	Storage Rights	54,614	1.83	999	0.44	240	(759)
354.00	Compressor Station Equipment	546,780	1.51	8,256	0.60	3,281	(4,976)
355.00	M&R Station Equipment	288,851	2.06	5,950	0.12	347	(5,604)
	Total Storage Plant	5,070,484	1.58	80,150	1.81	91,980	11,830
	TRANSMISSION PLANT						
365.20	Rights-of-Way	812,196	0.89	7,229	1.65	13,401	6,173
366.00	Structures and Improvements	283,237	1.39	3,937	2.05	5,806	1,869
367.00	Mains	22,044,698	1.27	279,968	1.85	407,827	127,859
369.00	M&R Station Equipment	2,952,222	2.28	67,311	1.48	43,693	(23,618)
	Total Transmission Plant	26,092,353	1.37	358,444	1.80	470,727	112,284
	DISTRIBUTION PLANT						
374.02	Land Rights	145,459	1.68	2,444	1.86	2,706	262
375.00	Structures and Improvements	468,328	1.95	9,132	3.18	14,893	5,760
376.00	Mains	95,924,845	2.39	2,292,604	2.43	2,330,974	38,370
378.00	M&R Station Equipment	2,617,970	2.49	65,187	1.92	50,265	(14,922)
379.00	City Gate Equipment	2,804,310	2.57	72,071	2.43	68,145	(3,926)
380.00	Services	69,190,312	6.86	4,746,455	5.23	3,618,653	(1,127,802)
381.00	Meters	13,775,723	3.35	461,487	8.06	1,110,323	648,837
382.00	Meter Installations	33,358,910	3.06	1,020,783	4.60	1,534,510	513,727
383.00	House Regulators	4,816,804	2.85	137,279	2.90	139,687	2,408
384.00	House Regulator Installations	154,276	3.37	5,199	2.02	3,116	(2,083)
385.00	Industrial M&R Equipment	4,433,322	2.73	121,030	2.61	115,710	(5,320)
	Total Distribution Plant	227,690,259	3.92	8,933,671	3.95	8,988,982	55,311
	GENERAL PLANT						
390.00	Structures and Improvements	966,202	2.12	20,483	9.91	95,751	75,267
390.09	Improvements to Leased Premises	1,382,343	5.00	69,117	2.36	32,623	(36,494)
391.00	Office Furniture and Equipment	2,305,350	7.05	162,527	6.22	143,393	(19,134)
392.00	Transportation Equipment	761,620	8.92	67,937	59.79	455,373	387,436
394.00	Tools, Shop and Garage Equipment	2,118,023	3.28	69,471	6.63	140,425	70,954
396.00	Power Operated Equipment	663,629	2.79	18,515	20.76	137,769	119,254
397.00	Communication Equipment	1,498,100	5.21	78,051	5.43	81,347	3,296
398.00	Miscellaneous Equipment	2,160,051	10.94	236,310	4.26	92,018	(144,291)
399.01	OTP - Servers Hardware	175,990	14.29	25,149	2.71	4,769	(20,380)
399.03	OTP - Network Hardware	511,781	14.29	73,134	5.22	26,715	(46,419)
399.06	OTP - PC Hardware	2,702,795	18.51	500,287	0.61	16,487	(483,800)
399.07	OTP - PC Software	242,979	15.85	38,512	19.16	46,555	8,043
399.08	OTP - Application Software	522,254	12.50	65,282	17.49	91,342	26,060
	Total General Plant	16,011,117	8.90	1,424,775	8.52	1,364,567	(60,208)
	Total Depreciable Plant	274,994,357	3.93	10,797,039	3.97	10,920,639	123,599
	Intangible Plant	128,183					
	Non-Depreciable Plant	486,462					
	Fully Depreciated Plant	2,303,510					
	Total Plant in Service	277,912,512					

ATMOS ENERGY CORPORATION - KENTUCKY **SCHEDULE 2**

Book Depreciation Study as of September 30, 2005

Comparison of Mortality Characteristics

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		EXISTING			RECOMMENDED					
Account	Description	ASL yrs.	Iowa Curve	Net Salvage %	ASL yrs.	Iowa Curve	Gross Salvage %	Cost of Removal %	Net Salvage %	COR Rate %
	PRODUCTION PLANT									
325.20	Producing Leaseholds	-	-	-	50	R5	0	0	0	
325.40	Rights-of-Way	-	-	-	50	R5	0	0	0	
336.00	Purification Equipment	-	-	-	50	R5	0	5	(5)	0.10
	STORAGE PLANT									
351.00	Structures and Improvements	45	R4	(5)	50	R2	5	0	5	
352.00	Well Construction and Equipment	50	R3	(50)	50	R3	0	40	(40)	0.80
352.03	Cushion Gas	-	-	-	50	SQ	0	0	0	
352.11	Storage Rights	40	R5	0	50	R5	0	0	0	
354.00	Compressor Station Equipment	40	S4	(10)	50	R1.5	0	0	0	
355.00	M&R Station Equipment	40	S1.5	0	50	R2	0	0	0	
	TRANSMISSION PLANT									
365.20	Rights-of-Way	60	R5	0	55	R5	0	0	0	
366.00	Structures and Improvements	45	R3	0	50	R3	0	0	0	
367.00	Mains	50	R5	(5)	55	R1	0	25	(25)	0.45
369.00	M&R Station Equipment	40	S1.5	0	45	R0.5	0	2	(2)	0.04
	DISTRIBUTION PLANT									
374.02	Land Rights	60	R5	0	55	R5	0	0	0	
375.00	Structures and Improvements	50	R3	0	50	L0	0	10	(10)	0.20
376.00	Mains	50	R1.5	(5)	55	R0.5	0	25	(25)	0.45
378.00	M&R Station Equipment	40	S1.5	0	50	R1	0	5	(5)	0.10
379.00	City Gate Equipment	40	S1.5	0	50	R1	0	15	(15)	0.30
380.00	Services	45	R1	(150)	40	R1.5	0	75	(75)	1.88
381.00	Meters	35	R2	0	25	R0.5	0	25	(25)	1.00
382.00	Meter Installations	35	R2	0	40	R1	0	25	(25)	0.63
383.00	House Regulators	35	R2	10	30	S6	0	0	0	
384.00	House Regulator Installations	35	R2	0	35	R2	0	0	0	
385.00	Industrial M&R Equipment	40	S1.5	0	40	L5	2	17	(15)	0.43
	GENERAL PLANT									
390.00	Structures and Improvements	45	R3	(5)	15	L2	0	0	0	
390.09	Improvements to Leased Premises	20	SQ	0	25	R4	0	0	0	
391.00	Office Furniture and Equipment	15	S4	5	18	L0	0	0	0	
392.00	Transportation Equipment	8	R1.5	15	8	S5	10	0	10	
394.00	Tools, Shop and Garage Equipment	30	S1	0	20	S6	1	0	1	
396.00	Power Operated Equipment	15	L2	10	15	L5	5	0	5	
397.00	Communication Equipment	15	S5	0	20	S2	0	0	0	
398.00	Miscellaneous Equipment	10	R3	0	20	R5	0	0	0	
399.01	OTP - Servers Hardware	7	SQ	0	10	SQ	0	0	0	
399.03	OTP - Network Hardware	7	SQ	0	10	SQ	0	0	0	
399.06	OTP - PC Hardware	5	R5	0	10	L1	2	0	2	
399.07	OTP - PC Software	5	R5	0	5	S1.5	0	0	0	
399.08	OTP - Application Software	8	SQ	0	8	R5	0	0	0	

CALCULATION OF EQUAL LIFE GROUP DEPRECIATION RATES

It is the group concept of depreciation that leads to the existence of the ELG procedure for calculating depreciation rates. This concept has been an integral part of utility depreciation accounting practices for many years. Under the group concept, there is no attempt to keep track of the depreciation applicable to individual items of property. This is not surprising, in view of the millions of items making up a utility system. Any item retired is assumed to be fully depreciated, no matter when the retirements occur. The group of property would have some average life. "Average" is the result of an arithmetic calculation, and there is no assurance that any of the property in the group is "average."

The term "average service life" used in the context of book depreciation is well known, and its use in the measurement of the mortality characteristics of property carries with it the concept of retirement dispersion. If every item was average, thereby having exactly the same life, there would be no dispersion. The concept of retirement dispersion recognizes that some items in a group live to an age less than average service life, and other items live longer than the average. Retirement dispersion is often identified by standard patterns.

The Iowa type dispersion patterns that are widely used by electric and gas utilities were devised empirically about 60 years ago to provide a set of standard definitions of retirement dispersion patterns. Figure 1 shows the dispersion patterns for three of these curves. The L series indicates the mode is to the Left of average service life, the R series to the Right, and the S series at average service life, and therefore, Symmetrical. There is also an O series which has the mode at the Origin, thereby identifying a retirement pattern that has the maximum percentage of original installations retired during the year of placement.

The subscripts on Figure 1 indicate the range of dispersion, with the high number (4) indicating a narrow dispersion, and the low number (1) indicating a wide dispersion pattern. For example, the R1 curve shown on the Figure indicates retirements start immediately and some of the property will last twice as long as the average service life. The dispersion patterns translate to survivor curves, which are the most widely recognized form of the Iowa curves. Other families of patterns exist, but are not as widely used as the Iowa type.

The methods of calculating depreciation rates are categorized as straight-line and non-straight-line. Non-straight-line methods can be accelerated or deferred. There are three basic procedures for calculating straight-line book depreciation rates:

Units-of-Production
Average Life Group (ALG)
Equal Life Group (ELG)

Each of these procedures can be calculated using either the whole life or the remaining life technique.

Productive life may be identified by (a) a life span or (b) a pattern of production or usage. Units-of-Production is straight-line over production or usage, while the others are straight-line over life measured by time. ALG is straight-line over the average life of the group, while ELG is straight-line over the actual life of the group.

The formulas for the whole life and remaining life techniques are shown on Table 1. For the ELG calculation procedure, Formulas 1 and 3 are applied to the individual equal life components of the property group. For the ALG calculation, the formulas are applied to the property group itself. Formula 2 is applied to the property group for either ELG or ALG. Use of the units (percent and years) in the formulas results in rates as a percent of the depreciable plant balance.

The depreciable plant balance is the surviving balance at the time the rate is calculated, and is expressed as a percentage (always 100) of itself. Salvage and reserves are expressed as a percent of the depreciable plant balance. For example, a property group having a 35 year average service life and negative 5% salvage would have an ALG whole life rate of (100 + 5)/35, or 3.00%.

The first term in Formula 2 is identical to Formula 1 for the whole life rate. The second term of Formula 2 illustrates that the difference between a remaining life rate and whole life rate is the allocation of the difference between the book and calculated theoretical reserves over the remaining life by a remaining life rate.

The widely used ALG procedure of depreciation rate calculation does not recognize the existence of retirement dispersion in the calculation. The difference between the ALG and ELG procedure is the recognition of retirement dispersion in the ELG rate calculation. ELG is a rate calculation procedure: nothing more. The data required to make the ELG calculation are average service life, retirement dispersion, net salvage and the age distribution of the property. The depreciation study required to determine the applicable mortality characteristics is independent from the calculation of the depreciation rates. The resulting mortality characteristics can be used to calculate either ALG or ELG rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG either. The ELG procedure calculates the depreciation rates based on the expected life of each equal life component of the property rather than the average of all components. As discussed earlier, “average” is the result of a calculation and there may not be any ”average” property. When curves are used to define retirement dispersion, the average service life and the retirement dispersion pattern define the equal life groups and the expected life applicable to each group.

When retirement dispersion does not exist, the ELG rate is identical to the ALG rate. When dispersion exists, the ELG rate for recently installed property is higher than the ALG rate and for old property is lower.

A Simple Illustration of ELG

This illustration provides a framework for visualizing the ELG methodology. Table 2 assumes 20% of the $5,000 investment is retired at the end of each year following placement. The retirement frequencies are shown on Line 7. As shown in Columns 2 through 6, this means $1,000 of investment is retired each year, with the retirement at Age 1 being recovered in its entirety during Year One; at Age 2 in Years One and Two, etc. The depreciation rate applicable to each equal life group is shown on Line 8. The annual provision in dollars for Year One shown in Column 7 is made up of the Age 1 annual amounts shown on Line 1, Columns 2 through 6. As shown on the Table, the annual provision for Age 2 is equal to the annual provision for Age 1 less the amount collected during Year One applicable to the group retired during Year One. Thus, the annual provisions can be thought of as a matrix, with the provision for any given year being produced by a portion of the matrix.

The depreciation rates shown in Column 9 are determined by dividing the annual provisions in Column 7 by the survivors in Column 8. The rate formula shown on Table 2 can also be used to calculate the rates and is used on the Table to illustrate the working of the matrix by calculating the depreciation rates for Year One and Year Three. For Year One, the numerator and denominator both consist of five terms. Each year, the left-hand term of both numerator and denominator drop off. It should be noted that the reverse summation of retirement ratios (starting with Column 6 and moving left on Line 7) is equal to the survivor ratio at the beginning of the period shown in Column 10.

The formula can illustrate how the matrix can be thought of in terms of a depreciation rate. If the multiplier of 100 is incorporated in each element of the numerator of the formula, such as (100 x 0.2)/2, it can be seen that 100/2 is a rate and the retirement frequency (0.2) is a weighting factor. This particular rate (50%) is the one shown for Age 2 property on Line 8, Column 3.

It can be seen that the only data required for the ELG rate calculation are the retirement frequencies for each year. These frequencies are defined by the average service life and the shape of the dispersion pattern.

<u>A Real Illustration of ELG</u>

The depreciation analyst deals with much larger groups of property than appearing on Table 2. Table 3 contains an ELG rate calculation for an actual depreciable property group. The retirement frequencies shown in Column 4 are defined by the 38 year average service life and the L5 Iowa type dispersion pattern. The ALG rate without salvage for this property is 2.632% (100%/38 years), while the ELG rate varies from 2.704% at age 0.5 years to 1.471% at the age just prior to the last retirement, 67.5 years.

The rate listed in Column 5 at each age is the weighted summation of individual rates applicable to that portion of the surviving property that the retirement frequencies in Column 4 indicate will be retired in each following year. The combination of average service life and dispersion pattern means that the first retirement will be from the age 18.5 property during the following year at an age of 19 years; therefore, it will require a rate of 5.263% (1005/19 years). (This example does not have any surviving balance at age 18.5). The last retirement will be from age 67.5 year property; consequently, it will require a rate of 1.471% (100%/68 years). The vintage composite rate shown in Column 5 at age 0.5 years is the weighted summation of rates varying from 5.263% to 1.471%.

Since this example is for a narrow dispersion pattern, the first retirement occurs at age 19 years and the vintage composite rate remains 2.704% at age 19.5 years, because the first retirement drops the 5.263% rate from the summation.

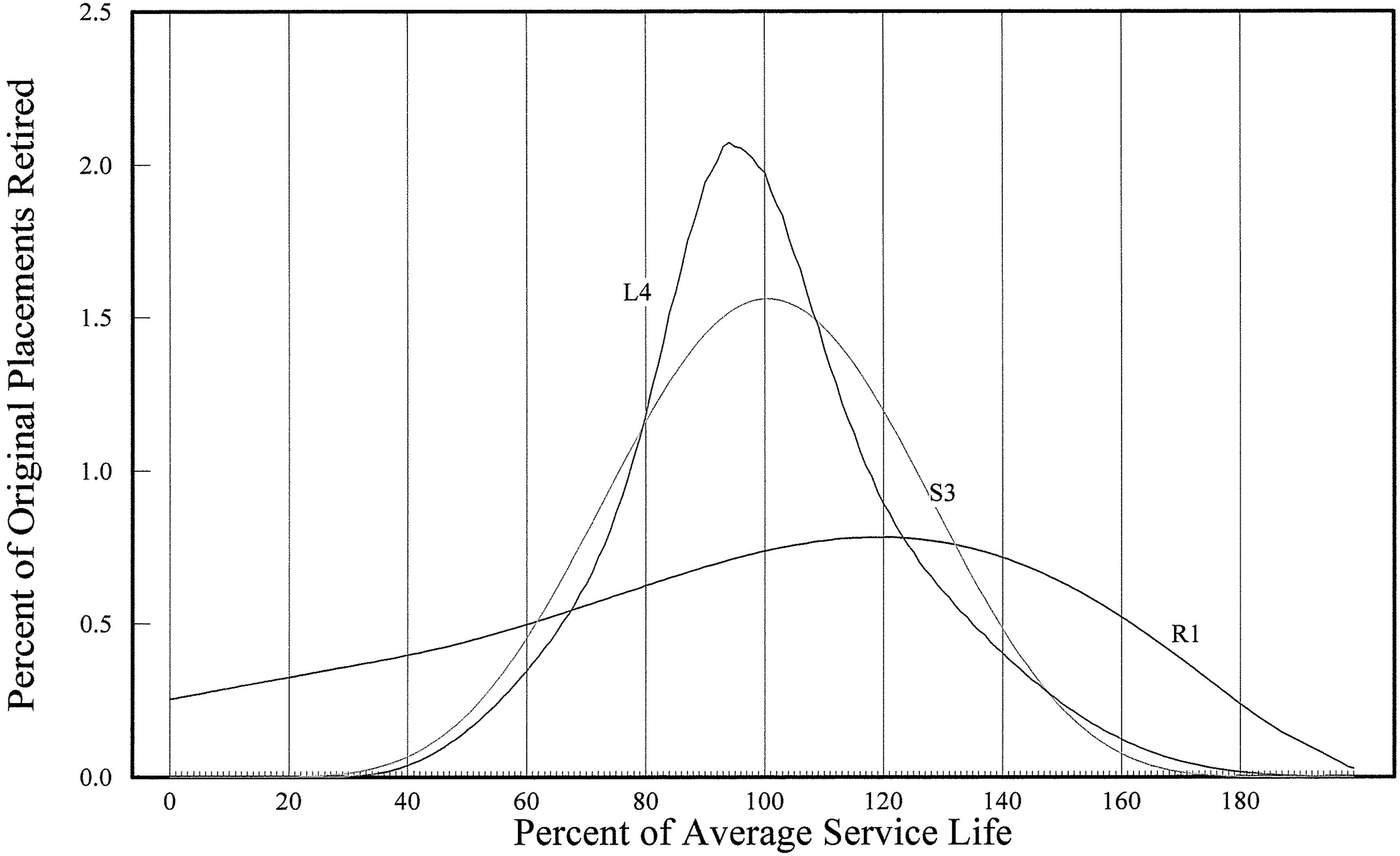
A wider dispersion would result in a wider range of vintage composite rates than defined by the L5 curve (i.e., 2.704% to 1.471%).

All that is necessary for calculating the depreciation rates applicable to each age of property are the retirement frequencies. These frequencies are defined by the average service life and the retirement dispersion pattern. The determination of average service life requires the determination of the dispersion, as without dispersion there would be no "average".

Depending on the dispersion pattern, the number of retirement frequencies making up the complete curve can be up to about 4.4 times the number of years of average service life. Thus, for an account whose number of retirement frequencies is three times average service life and whose average service life is 30 years, the rate applicable to the Age 1 property will be made up of the weighted summation of 89 components, etc. Thus, the rate calculation process is complex, but certainly not complicated. It is this complexity that makes the rate calculations much more practical using a computer.

RETIREMENT DISPERSION DEFINED

BY IOWA TYPE CURVES



DEPRECIATION RATE CALCULATION PROCEDURES

TABLE 1

Whole Life

$$\text{Rate (\%)} = \frac{PB - S}{ASL} \qquad \text{Formula 1}$$

Remaining Life

$$\text{Rate (\%)} = \frac{PB - FS}{ASL} - \frac{BR - CT}{ARL} \qquad \text{Formula 2}$$

$$\text{Rate (\%)} = \frac{PB - FS - BR}{ARL} \qquad \text{Formula 3}$$

Where

PB	is Depreciable Balance, %
AS	is Average Net Salvage, %
FS	is Future Net Salvage, %
ASL	is Average Service Life, years
BR	is Depreciation Reserve, %
CTR	is Calculated Theoretical Reserve, %
ARL	is Average Remaining Life, years

TABLE 2

DEVELOPMENT OF EQUAL LIFE GROUP CAPITAL RECOVERY RATE

Line	(1) Age Years	(2) Group 1 $	(3) Group 2 $	(4) Group 3 $	(5) Group 4 $	(6) Group 5 $	(7) Annual Provision $	(8) Beginning Survivors $	(9) Rate %	(10) Survivor Factor
1	1	1,000.00	500.00	333.33	250.00	200.00	2,283.33	5,000.00	45.67	1.00
2	2		500.00	333.33	250.00	200.00	1,283.33	4,000.00	32.08	0.80
3	3			333.33	250.00	200.00	783.33	3,000.00	26.11	0.60
4	4				250.00	200.00	450.00	2,000.00	22.50	0.40
5	5					200.00	200.00	1,000.00	20.00	0.20
6	Retirements	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00				
7	Frequency	0.20	0.20	0.20	0.20	0.20				
8	Rate	100%	50%	33.33%	25%	20%				

$$\text{Rate, \%} = \frac{\dfrac{\text{Retirements Frequencies}}{\text{Age at Retirement}}}{\text{Reverse of Retirement Frequencies}} \times 100$$

$$\text{Year One Rate} = \frac{\dfrac{0.2}{1} + \dfrac{0.2}{2} + \dfrac{0.2}{3} + \dfrac{0.2}{4} + \dfrac{0.2}{5}}{0.2 + 0.2 + 0.2 + 0.2 + 0.2} \times 100 = 45.67\%$$

$$\text{Year Three Rate} = \frac{\dfrac{0.2}{3} + \dfrac{0.2}{4} + \dfrac{0.2}{5}}{0.2 + 0.2 + 0.2} \times 100 = 26.11\%$$

DETERMINATION OF DEPRECIATION RATES BY ELG PROCEDURES

[1] Age Years	[2] Year	[3] Vintage Balance $	[4] Retirement Frequency ASL 38 Curve L5	[5] Rate	[6] Amount $
0.5	1993	4,244,285	0.0000	0.02704	114,758.36
1.5	1992	800,784	0.0000	0.02704	21,651.86
2.5	1991	60,016	0.0000	0.02704	1,622.73
3.5	1990	43,455,063	0.0000	0.02704	1,174,952.00
4.5	1989	81,456	0.0000	0.02704	2,202.43
5.5	1988	172,463	0.0000	0.02704	4,663.11
6.5	1987	2,098,991	0.0000	0.02704	56,753.20
7.5	1986	2,685,949	0.0000	0.02704	72,623.55
9.5	1984	1,642,443	0.0000	0.02704	44,408.90
10.5	1983	222,602	0.0000	0.02704	6,018.78
11.5	1982	85,661	0.0000	0.02704	2,316.13
12.5	1981	4,985	0.0000	0.02704	134.79
13.5	1980	72,942	0.0000	0.02704	1,972.23
14.5	1979	219,163	0.0000	0.02704	5,925.80
15.5	1978	120,665	0.0000	0.02704	3,262.58
16.5	1977	37,042	0.0000	0.02704	1,001.55
17.5	1976	339,236	0.0000	0.02704	9,172.21
19.5	1974	336,723	0.0001	0.02703	9,101.41
20.5	1973	10,375,359	0.0004	0.02702	280,292.86
21.5	1972	4,481,906	0.0009	0.02699	120,963.25
22.5	1971	5,923,340	0.0018	0.02695	159,618.98
23.5	1970	78,848	0.0030	0.02689	2,119.97
24.5	1969	305,178	0.0047	0.02681	8,180.42
25.5	1968	10,312,586	0.0069	0.02670	275,375.94
26.5	1967	2,754,067	0.0094	0.02658	73,203.24
27.5	1966	9,558,786	0.0123	0.02644	252,715.77
29.5	1964	5,556,083	0.0194	0.02610	144,995.54
30.5	1963	23,383	0.0242	0.02589	605.42
31.5	1962	3,313,564	0.0305	0.02566	85,012.50
32.5	1961	32,271	0.0386	0.02538	819.15
33.5	1960	151,658	0.0482	0.02507	3,802.24
34.5	1959	171,483	0.0583	0.02472	4,238.70
35.5	1958	167,116	0.0674	0.02433	4,065.35
36.5	1957	70,420	0.0740	0.02390	1,683.22
37.5	1956	1,792,312	0.0768	0.02345	42,036.33
39.5	1954	2,270,555	0.0701	0.02252	51,131.79
40.5	1953	187	0.0622	0.02206	4.13
41.5	1952	20,185	0.0531	0.02161	436.14
42.5	1951	12,860	0.0442	0.02118	272.40
43.5	1950	706	0.0362	0.02078	14.67
44.5	1949	2,652	0.0296	0.02041	54.13
45.5	1948	6,422	0.0245	0.02006	128.81
46.5	1947	19,573	0.0205	0.01972	386.07
47.5	1946	323,058	0.0173	0.01940	6,268.69
49.5	1944	2,285,041	0.0123	0.01879	42,943.47
50.5	1943	15,614	0.0103	0.01850	288.86
51.5	1942	620,752	0.0085	0.01821	11,306.36
53.5	1940	684,610	0.0055	0.01766	12,090.28
54.5	1939	47,173	0.0043	0.01740	820.76
55.5	1938	22,725	0.0033	0.01714	389.52
56.5	1937	560	0.0025	0.01689	9.46
57.5	1936	722	0.0019	0.01664	12.02
59.5	1934	3,065	0.0005	0.01573	48.21
61.5	1932	944,400	0.0005	0.01573	14,853.98
67.5	1926	2	0.0000	0.01471	0.03
Totals		119,029,691			3,133,730.27
			SALVAGE (%) =		-5.0
			AFTER SALVAGE =		3,290,417
		ANNUAL DEPRECIATION RATE =			2.76

EXHIBIT DSR-4

Depreciation Specialty Resources

Atmos Energy Corporation

Book Depreciation Study of Atmos Energy Corporation Shared Services Unit As of September 30, 2006

2832 Gainesborough Drive, Dallas, TX 75287-3483 469-964-9090

Atmos Energy Corporation

Book Depreciation Study of
Atmos Energy Corporation
Shared Services Properties
As of September 30, 2006

December 2006

Atmos Energy Corporation
Three Lincoln Center
5430 LBJ Freeway
Dallas, TX 75240

Attention: Mr. Thomas Petersen

In accordance with your request and with the cooperation and participation of your staff, a book depreciation study of Atmos Energy Corporation's Shared Services ("SSU") properties ("Atmos" or "the Company") has been conducted. The study covered all depreciable and amortizable property and recognized addition and retirement experience through September 30, 2006. The purpose of the study was to determine if the existing depreciation rates remain appropriate for the property and, if not, to recommend changes. Changes were found to be needed and are recommended. The changes in aggregate cause an increase in depreciation rates used to calculate the annual depreciation expense.

A comparison of the effect of the existing rates and the recommended rates is shown below, based on depreciable plant balances as of September 30, 2006:

Function	Composite Depreciation Rate	
	Existing	Recommended
	%	%
General	9.09	10.32

The summary above is taken from Schedule 1, which shows the annual depreciation amounts calculated from the existing rates and the recommended account rates and the differences. Based upon the September 30, 2006 depreciable balances, the recommended depreciation rates will result in an annual increase in depreciation provisions of $2,662,501 or 13.5%.

Schedule 2 shows the mortality characteristics used to calculate the recommended depreciation rates. The recommended depreciation rates are straight-line over life measured by time using the equal life group (ELG) procedure and the remaining life technique, consistent with the existing, approved rates.

The following sections of this report describe the methods of analysis used and the bases for the conclusions reached. The remainder of the report will present the results and recommendations for both immediate and future actions by the Company.

We appreciate this opportunity to serve Atmos Energy Corporation and would be pleased to meet with you to discuss further the matters presented in this report, if you desire.

Yours truly,

Donald S. Roff

President

Depreciation Specialty Resources

PURPOSE OF DEPRECIATION

Book depreciation accounting is the process of recognizing in financial statements the consumption of physical assets in the process of providing a service or a product. Generally accepted accounting principles require the recording of depreciation to be systematic and rational. To be systematic and rational, depreciation should, to the extent possible, match either the consumption of the facilities or the revenues generated by the facilities. Accounting theory requires the matching of expenses with either consumption or revenues to ensure that financial statements reflect the results of operations and changes in financial position as accurately as possible. The matching principle is often referred to as the "cause and effect" principle; thus, both the cause and the effect are required to be recognized for financial accounting purposes. This study was conducted in a manner consistent with the matching principle of accounting.

Because utility revenues are determined through regulation, and this study assumes that such regulation will continue, asset consumption is not automatically in revenues. Therefore, the consumption of utility assets must be measured directly by conducting a book depreciation study to accurately determine the mortality characteristics of the assets.

Matching is also an essential element of basic regulatory philosophy, and it has become known as "intergenerational customer equity". Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that the charges to customers reflect the actual costs of providing service.

<u>DEPRECIATION DEFINTIONS</u>

The Uniform System of Accounts ("USOA") prescribed for gas utilities by the Federal Energy Regulatory Commission ("FERC") followed by Atmos states that:

> "Depreciation", as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and in the case of natural gas companies, the exhaustion of natural resources.
>
> "Service value" means the difference between original cost and net salvage value of gas plant.
>
> "Net salvage value" means the salvage value of property retired less the cost of removal.
>
> "Salvage value" means the amount received for the property retired, less any expenses incurred in connection with the sale or in preparing the property for sale or, if retained, the amount at which the material is chargeable to materials and supplies, or other appropriate account.
>
> "Cost of removal" means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto.

As is clear from the wording of the salvage value and the cost of removal definitions, it is the salvage that will actually be received and the cost of removal that will actually be incurred, both measured at the price level at the time of receipt or incurrence that is required to be recognized in the depreciation rates of Atmos.

These definitions are consistent with the purpose of depreciation, and the study reported here was conducted in a manner consistent with both.

ACCOMPLISHMENT OF ACCOUNTING AND REGULATORY PRINCIPLES

Utility depreciation accounting is a group concept. Inherent in this concept is the assumption that all property is fully depreciated at the time of retirement, regardless of age, and there is no attempt to record the depreciation applicable to individual components of the groups. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property group is "average". The group carries with it recognition that most property will be retired at an age less than or greater than the average service life. This study recognized the existence of this variation through the identification of Iowa-type retirement dispersions.

The study required to determine the applicable mortality characteristics is independent from the calculation of depreciation rates. The resulting mortality characteristics can be used to calculate either Average Life Group ("ALG") or Equal Life Group ("ELG") rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG. ALG and ELG are straight-line over life measured by time, with ALG utilizing average life and ELG utilizing actual life. For ALG, all property in the group is assumed to have a life equal to the average life. ELG recognizes that, in reality, only a small portion of the group retires at an age equal to the average service life. For the average to exist, about half the investment in an asset group will be retired at ages less than average life, a small amount at average life, and the rest at ages greater than average life. It is the use of this dispersion in the rate calculation that causes ELG rates to better match cost recovery with the use and benefit of the property. Thus, the ELG procedure best accomplishes the purpose of book depreciation accounting by ensuring the recording of depreciation provision match the actual consumption of physical assets. Since ELG matches the recording of consumption with actual consumption, customers will pay the actual cost incurred to serve them. The ELG procedure is recommended, consistent with the existing, approved rates. A detailed discussion of the ELG procedure is included in the Appendix A to this report.

THE BOOK DEPRECIATION STUDY

Implementation of a policy toward book depreciation that recognizes the purpose of depreciation accounting requires the determination of the mortality characteristics that are applicable to the surviving property. One purpose of the depreciation study reported here was to accurately measure those mortality characteristics and to use those characteristics to determine appropriate rates for the accrual of depreciation expenses.

The major effort of the study was the determination of the appropriate mortality characteristics. The remainder of this report describes how those characteristics were determined, describes how the mortality characteristics were used to calculate the recommended depreciation rates, and presents the results of the rate calculations.

The typical study consists of the following steps:

> Step One is a Life Analysis consisting of the determination of historical experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Two is a Salvage and Cost of Removal Analysis consisting of a study of salvage and cost of removal experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Three consists of the determination of average service lives, retirement dispersion patterns identified by Iowa-type curves and the net salvage factors applicable to the surviving property.
>
> Step Four is the determination of the depreciation rate applicable to each depreciable property group recognizing the results of the work in Steps One through Three, and a comparison with the existing depreciation rates.

LIFE ANALYSIS

The Life Analysis for the property concerns the determination of average service lives ("ASL") and Iowa-type dispersion patterns. An evaluation of investment experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of average service lives and retirement dispersions.

An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving plant, formed the basis for the determination of average service lives and retirement dispersion patterns for all property groups. Retirement experience from transaction years 1987 through 2006 were analyzed using the Actuarial Method of Life Analysis. This method could be used because aged data are available for certain asset categories.

The actuarial method determines actual survivor curves (observed life tables) for selected periods of actual retirement experience. In order to recognize trends in life characteristics and to ensure that the valuable information in the curves is available to the analyst, observed life tables were calculated and plotted by computer, using several different periods of retirement experience. The average service lives and retirement dispersion patterns indicated by the actual survivor curves were identified by visually fitting Iowa-type dispersion curves to the actual curves. Retirement dispersion refers to the pattern of retirements as a function of age over the life of each property group. For each asset category, an Iowa-type curve combined with an estimated average service life was selected. This selection was based upon an analysis of historical investment activity, associated mortality trends and the types of assets surviving and retiring. The workpapers prepared as an integral part of the depreciation study contain the rationale for each selection.

Trends in historical mortality experience are helpful in understanding history. In order to determine trends, the periods (year bands) of retirement experience analyzed were the past five years, the past ten years, the past fifteen years, the past twenty years and the full band of band of retirement experience. The observed life tables and the Iowa curves fitted to each of these year bands were plotted. This visual approach ensures that the data contained in the observed life tables are available to the analyst and that the analyst does not allow the computer calculations to be the sole determinant of study results.

For accounts having little experience or having retirement experience that is not an adequate measure of the expected mortality characteristics of surviving property, evaluation of the significance of history played a major role in selecting the mortality characteristics shown on Schedule 2.

SALVAGE AND COST OF REMOVAL ANALYSIS

Salvage and cost of removal experience was analyzed using experience from the period 1993 – 2006. Rolling and shrinking bands were analyzed to help expose trends. An evaluation of salvage and cost of removal experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of salvage and cost of removal factors.

The analysis consisted of calculating salvage and cost of removal factors by relating the recorded salvage and cost of removal for each property group to the retirements that caused the salvage and cost of removal to occur.

EVALUATION OF ACTUAL EXPERIENCE

The typical evaluation consists of Life Analysis and Salvage and Cost of Removal Analysis, which involve the measurement of what has occurred in the past. History is sometimes a misleading indicator of the future. There are many kinds of events that can cause history to be misleading, among them significant changes contemplated in the underlying accounting procedures and/or changes in other management practices, such as maintenance procedures. It is the evaluation phase of a depreciation study that identifies if history is a good indicator of the future. Blind acceptance of history often results in selecting mortality characteristics to use for calculating depreciation rates that will provide recovery over a time period longer than productive life.

For each property group, the typical analysis processes involve only historical investment experience. Since depreciation rates will be applied to surviving property, the historical mortality experience indicated by a Life Analysis and the Salvage and Cost of Removal Analysis is evaluated to ensure that the mortality characteristics used to calculate the depreciation rates are applicable to the surviving property. The evaluation is required to ensure the validity of the depreciation rates.

The normal evaluation process requires knowledge of the type of property surviving; the type of property retired; the reasons for changing life, dispersion, salvage and cost of removal; and the effect of present and future Atmos plans on the property mortality characteristics.

CALCULATION OF DEPRECIATION RATES

A straight-line remaining life rate for each depreciable property group was calculated using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance} - \text{Future Net Salvage} - \text{Book Reserve}}{\text{Average Remaining Life}}$$

Formula numerator elements in percent of depreciable plant balance and the denominator in years produce a rate in percent. This formula illustrates that a remaining life rate recognizes the book reserve position. The depreciable balances and book reserves were taken from accounting records, and the net salvage factors were determined by the study.

The remaining lives for each property group are a function of the age distribution of surviving plant and the selected average service life and retirement dispersion.

RESULTS

A comparison of the existing depreciation rates to the proposed study depreciation rates can be found on Schedule 1 in this report. A listing, by account, of the existing and the proposed mortality characteristics can be found on Schedule 2 in this report.

General Plant

There is an increase in the depreciation rate indicated for this asset category from 9.09% to 10.32%. Average service life changes are an increase for all accounts except two. The single largest change in annual depreciation expense is for Account 399.08, Application Software. The recommended average service life is 10 years with an S3 curve. Net salvage is estimated to be 0%. The annual depreciation expense increase is $3,217,244, and is primarily due to reserve position. There are two other significant changes in depreciation expense occurring for Account 399.01, Server Software and Account 399.24, General Start-up Costs. There is a decrease in annual depreciation expense for Account 399.01 of $1,069,241, due to a longer average service life. There is an increase in annual depreciation expense for Account 399.24 of $1,751,828, due to reserve position.

RESERVE COMPARISON

Because remaining life rates are recommended (consistent with the existing rates), a comparison of the accumulated provision for depreciation with the calculated theoretical reserve at September 30, 2006, is not meaningful, and no comparison is presented. This is because the only way a reserve difference can exist is through the use of whole life rates.

RECOMMENDATIONS

Our recommendations for your future action in regard to book depreciation are as follows:

1. The depreciation rates shown in Column 6 of Schedule 1 are applicable to existing property and are recommended for implementation at such time as their effect can be incorporated into service rates.

2. Because of variation of life and net salvage experience with time, a depreciation study should be made during 2011 based upon retirement experience through September 30, 2010. Exact timing of the study should be coordinated with a retail rate case to ensure timely implementation of revised depreciation rates.

3. We recommend that Atmos consider the utilization of a vintage amortization accounting process. This approach has been implemented by numerous utilities all over the country. This approach solves the universal problem of unreported retirements, is intended to simplify the property accounting effort, and provides a better matching of the accounting effort with the magnitude of the asset base.

4. For new asset categories that arise in the future for which no depreciation rate is currently approved, or for asset categories that are presently fully depreciated and may have new assets added in the future, we recommend that the functional composite depreciation rates be used until future depreciation studies are conducted. The functional composite depreciation rate is as follows:

General Plant	10.32%

ATMOS ENERGY CORPORATION - SHARED SERVICES

SCHEDULE 1

Book Depreciation Study as of September 30, 2006
Comparison of Depreciation Rates and Annual Amounts

[1] Account Number	[2] Description	[3] 9/30/2006 Balance $	[4] Existing Rates %	[5] Annual Amount $	[6] Study Rates %	[7] Annual Amount $	[8] Increase or (Decrease) $
	GENERAL PLANT						
390.09	Improvements to Leased Premises	9,949,143	7.43	739,221	9.10	905,372	166,151
391.00	Office Furniture and Equipment	9,074,352	4.89	443,736	2.13	193,284	(250,452)
397.00	Communication Equipment	25,311,861	7.12	1,802,205	8.45	2,138,852	336,648
398.00	Miscellaneous Equipment	633,466	5.36	33,954	8.15	51,627	17,674
399.00	Other Tangible Property	224,866	15.75	35,416	4.66	10,479	(24,938)
399.01	Servers Hardware	14,567,322	14.29	2,081,670	6.95	1,012,429	(1,069,241)
399.02	Servers Software	8,647,580	14.29	1,235,739	4.00	345,903	(889,836)
399.03	Network Hardware	2,377,029	14.29	339,677	9.30	221,064	(118,614)
399.06	PC Hardware	6,691,156	16.83	1,126,122	14.86	994,306	(131,816)
399.07	PC Software	3,928,199	17.73	696,470	9.02	354,324	(342,146)
399.08	Application Software	111,323,312	8.22	9,150,776	11.11	12,368,020	3,217,244
399.24	General Startup Cost	23,172,326	8.33	1,930,255	15.89	3,682,083	1,751,828
	Total Depreciable General Plant	215,900,612	9.09	19,615,241	10.32	22,277,742	2,662,501
	Fully Depreciated	5,331,910					
	Late Retirements	4,363,383					
	Total Shared Services Facilities	225,595,905					

SCHEDULE 2

ATMOS ENERGY CORPORATION - SHARED SERVICES
Book Depreciation Study as of September 30, 2006
Comparison of Mortality Characteristics

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		EXISTING PARAMETERS			STUDY PARAMETERS				
Account Number	Description	ASL yrs.	Iowa Curve	Net Salvage %	ASL yrs.	Iowa Curve	Gross Salvage %	Cost of Removal %	Net Salvage %
	GENERAL PLANT								
390.09	Improvements to Leased Premises	10.0	SQ	0	12.0	S4	0	0	0
391.00	Office Furniture and Equipment (Gnl)	30.0	R2	0	25.0	R4	0	0	0
397.00	Communication Equipment	10.0	L3	0	12.0	S5	0	0	0
398.00	Miscellaneous Equipment	10.0	S6	5	15.0	S3	5	0	5
399.00	Other Tangible Property	5.0	SQ	0	7.0	R5	0	0	0
399.01	Servers Hardware	5.0	SQ	0	10.0	SQ	0	0	0
399.02	Servers Software	5.0	SQ	0	10.0	SQ	0	0	0
399.03	Network Hardware	5.0	SQ	0	10.0	SQ	0	0	0
399.06	PC Hardware	4.0	SQ	0	7.0	S1	0	0	0
399.07	PC Software	4.0	SQ	0	8.5	R5	0	0	0
399.08	Application Software	8.0	S1.5	0	10.0	S3	0	0	0
399.24	General Startup Cost	10.0	SQ	0	10.0	SQ	0	0	0

CALCULATION OF EQUAL LIFE GROUP DEPRECIATION RATES

It is the group concept of depreciation that leads to the existence of the ELG procedure for calculating depreciation rates. This concept has been an integral part of utility depreciation accounting practices for many years. Under the group concept, there is no attempt to keep track of the depreciation applicable to individual items of property. This is not surprising, in view of the millions of items making up a utility system. Any item retired is assumed to be fully depreciated, no matter when the retirements occur. The group of property would have some average life. "Average" is the result of an arithmetic calculation, and there is no assurance that any of the property in the group is "average."

The term "average service life" used in the context of book depreciation is well known, and its use in the measurement of the mortality characteristics of property carries with it the concept of retirement dispersion. If every item was average, thereby having exactly the same life, there would be no dispersion. The concept of retirement dispersion recognizes that some items in a group live to an age less than average service life, and other items live longer than the average. Retirement dispersion is often identified by standard patterns.

The Iowa type dispersion patterns that are widely used by electric and gas utilities were devised empirically about 60 years ago to provide a set of standard definitions of retirement dispersion patterns. Figure 1 shows the dispersion patterns for three of these curves. The L series indicates the mode is to the Left of average service life, the R series to the Right, and the S series at average service life, and therefore, Symmetrical. There is also an O series which has the mode at the Origin, thereby identifying a retirement pattern that has the maximum percentage of original installations retired during the year of placement.

The subscripts on Figure 1 indicate the range of dispersion, with the high number (4) indicating a narrow dispersion, and the low number (1) indicating a wide dispersion pattern. For example, the R1 curve shown on the Figure indicates retirements start immediately and some of the property will last twice as long as the average service life. The dispersion patterns translate to survivor curves, which are the most widely recognized form of the Iowa curves. Other families of patterns exist, but are not as widely used as the Iowa type.

The methods of calculating depreciation rates are categorized as straight-line and non-straight-line. Non-straight-line methods can be accelerated or deferred. There are three basic procedures for calculating straight-line book depreciation rates:

Units-of-Production
Average Life Group (ALG)
Equal Life Group (ELG)

Each of these procedures can be calculated using either the whole life or the remaining life technique.

Productive life may be identified by (a) a life span or (b) a pattern of production or usage. Units-of-Production is straight-line over production or usage, while the others are straight-line over life measured by time. ALG is straight-line over the average life of the group, while ELG is straight-line over the actual life of the group.

The formulas for the whole life and remaining life techniques are shown on Table 1. For the ELG calculation procedure, Formulas 1 and 3 are applied to the individual equal life components of the property group. For the ALG calculation, the formulas are applied to the property group itself. Formula 2 is applied to the property group for either ELG or ALG. Use of the units (percent and years) in the formulas results in rates as a percent of the depreciable plant balance.

The depreciable plant balance is the surviving balance at the time the rate is calculated, and is expressed as a percentage (always 100) of itself. Salvage and reserves are expressed as a percent of the depreciable plant balance. For example, a property group having a 35 year average service life and negative 5% salvage would have an ALG whole life rate of (100 + 5)/35, or 3.00%.

The first term in Formula 2 is identical to Formula 1 for the whole life rate. The second term of Formula 2 illustrates that the difference between a remaining life rate and whole life rate is the allocation of the difference between the book and calculated theoretical reserves over the remaining life by a remaining life rate.

The widely used ALG procedure of depreciation rate calculation does not recognize the existence of retirement dispersion in the calculation. The difference between the ALG and ELG procedure is the recognition of retirement dispersion in the ELG rate calculation. ELG is a rate calculation procedure: nothing more. The data required to make the ELG calculation are average service life, retirement dispersion, net salvage and the age distribution of the property. The depreciation study required to determine the applicable mortality characteristics is independent from the calculation of the depreciation rates. The resulting mortality characteristics can be used to calculate either ALG or ELG rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG either. The ELG procedure calculates the depreciation rates based on the expected life of each equal life component of the property rather than the average of all components. As discussed earlier, "average" is the result of a calculation and there may not be any "average" property. When curves are used to define retirement dispersion, the average service life and the retirement dispersion pattern define the equal life groups and the expected life applicable to each group.

When retirement dispersion does not exist, the ELG rate is identical to the ALG rate. When dispersion exists, the ELG rate for recently installed property is higher than the ALG rate and for old property is lower.

A Simple Illustration of ELG

This illustration provides a framework for visualizing the ELG methodology. Table 2 assumes 20% of the $5,000 investment is retired at the end of each year following placement. The retirement frequencies are shown on Line 7. As shown in Columns 2 through 6, this means $1,000 of investment is retired each year, with the retirement at Age 1 being recovered in its entirety during Year One; at Age 2 in Years One and Two, etc. The depreciation rate applicable to each equal life group is shown on Line 8. The annual provision in dollars for Year One shown in Column 7 is made up of the Age 1 annual amounts shown on Line 1, Columns 2 through 6. As shown on the Table, the annual provision for Age 2 is equal to the annual provision for Age 1 less the amount collected during Year One applicable to the group retired during Year One. Thus, the annual provisions can be thought of as a matrix, with the provision for any given year being produced by a portion of the matrix.

The depreciation rates shown in Column 9 are determined by dividing the annual provisions in Column 7 by the survivors in Column 8. The rate formula shown on Table 2 can also be used to calculate the rates and is used on the Table to illustrate the working of the matrix by calculating the depreciation rates for Year One and Year Three. For Year One, the numerator and denominator both consist of five terms. Each year, the left-hand term of both numerator and denominator drop off. It should be noted that the reverse summation of retirement ratios (starting with Column 6 and moving left on Line 7) is equal to the survivor ratio at the beginning of the period shown in Column 10.

The formula can illustrate how the matrix can be thought of in terms of a depreciation rate. If the multiplier of 100 is incorporated in each element of the numerator of the formula, such as (100 x 0.2)/2, it can be seen that 100/2 is a rate and the retirement frequency (0.2) is a weighting factor. This particular rate (50%) is the one shown for Age 2 property on Line 8, Column 3.

It can be seen that the only data required for the ELG rate calculation are the retirement frequencies for each year. These frequencies are defined by the average service life and the shape of the dispersion pattern.

<u>A Real Illustration of ELG</u>

The depreciation analyst deals with much larger groups of property than appearing on Table 2. Table 3 contains an ELG rate calculation for an actual depreciable property group. The retirement frequencies shown in Column 4 are defined by the 38 year average service life and the L5 Iowa type dispersion pattern. The ALG rate without salvage for this property is 2.632% (100%/38 years), while the ELG rate varies from 2.704% at age 0.5 years to 1.471% at the age just prior to the last retirement, 67.5 years.

The rate listed in Column 5 at each age is the weighted summation of individual rates applicable to that portion of the surviving property that the retirement frequencies in Column 4 indicate will be retired in each following year. The combination of average service life and dispersion pattern means that the first retirement will be from the age 18.5 property during the following year at an age of 19 years; therefore, it will require a rate of 5.263% (1005/19 years). (This example does not have any surviving balance at age 18.5). The last retirement will be from age 67.5 year property; consequently, it will require a rate of 1.471% (100%/68 years). The vintage composite rate shown in Column 5 at age 0.5 years is the weighted summation of rates varying from 5.263% to 1.471%.

Since this example is for a narrow dispersion pattern, the first retirement occurs at age 19 years and the vintage composite rate remains 2.704% at age 19.5 years, because the first retirement drops the 5.263% rate from the summation.

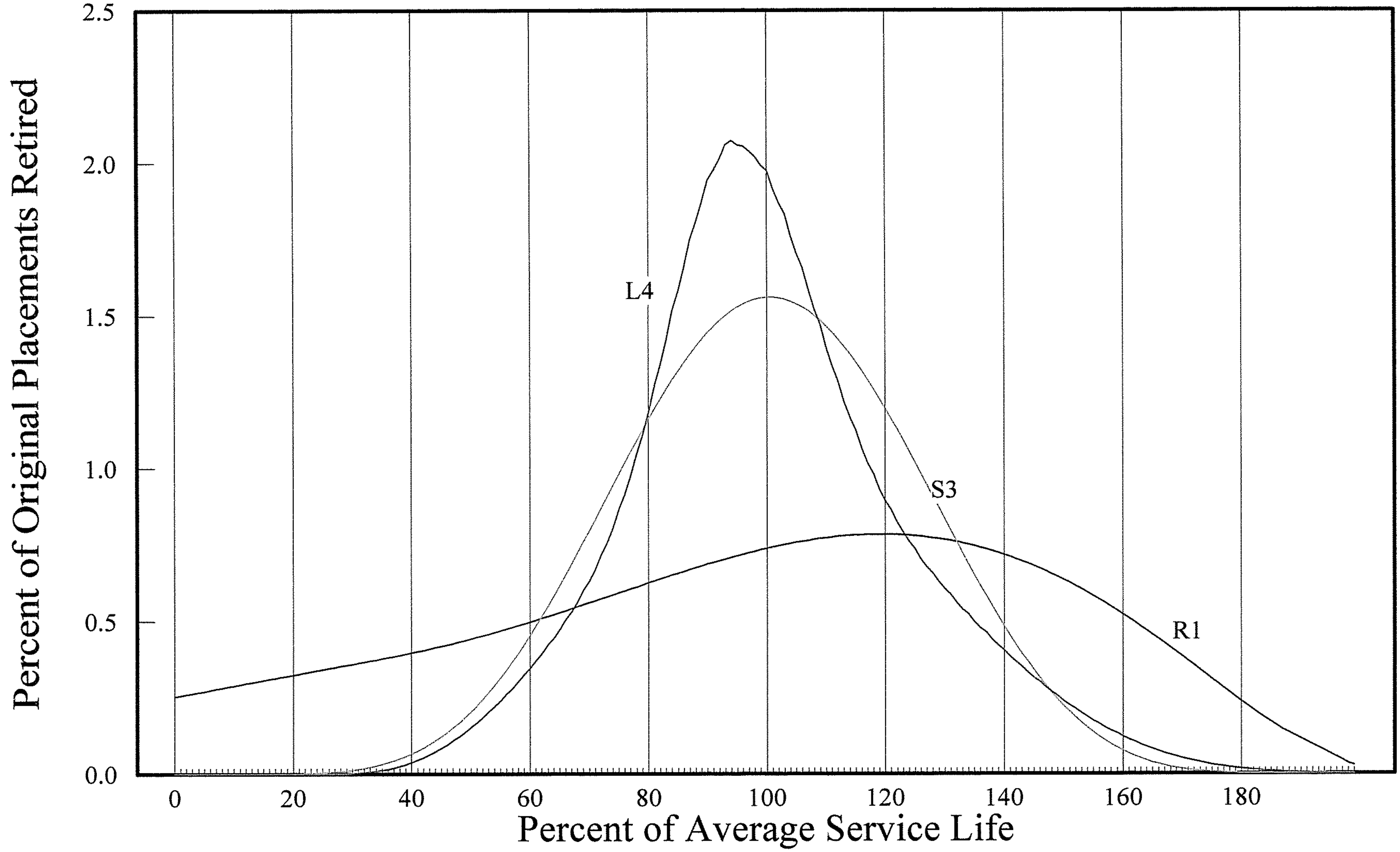
A wider dispersion would result in a wider range of vintage composite rates than defined by the L5 curve (i.e., 2.704% to 1.471%).

All that is necessary for calculating the depreciation rates applicable to each age of property are the retirement frequencies. These frequencies are defined by the average service life and the retirement dispersion pattern. The determination of average service life requires the determination of the dispersion, as without dispersion there would be no "average".

Depending on the dispersion pattern, the number of retirement frequencies making up the complete curve can be up to about 4.4 times the number of years of average service life. Thus, for an account whose number of retirement frequencies is three times average service life and whose average service life is 30 years, the rate applicable to the Age 1 property will be made up of the weighted summation of 89 components, etc. Thus, the rate calculation process is complex, but certainly not complicated. It is this complexity that makes the rate calculations much more practical using a computer.

RETIREMENT DISPERSION DEFINED

BY IOWA TYPE CURVES



DEPRECIATION RATE CALCULATION PROCEDURES

TABLE 1

Whole Life

$$\text{Rate (\%)} = \frac{PB - S}{ASL} \qquad \text{Formula 1}$$

Remaining Life

$$\text{Rate (\%)} = \frac{PB - FS}{ASL} - \frac{BR - CT}{ARL} \qquad \text{Formula 2}$$

$$\text{Rate (\%)} = \frac{PB - FS - BR}{ARL} \qquad \text{Formula 3}$$

Where

PB	is Depreciable Balance, %
AS	is Average Net Salvage, %
FS	is Future Net Salvage, %
ASL	is Average Service Life, years
BR	is Depreciation Reserve, %
CTR	is Calculated Theoretical Reserve, %
ARL	is Average Remaining Life, years

TABLE 2

DEVELOPMENT OF EQUAL LIFE GROUP CAPITAL RECOVERY RATE

Line	(1) Age Years	(2) Group 1 $	(3) Group 2 $	(4) Group 3 $	(5) Group 4 $	(6) Group 5 $	(7) Annual Provision $	(8) Beginning Survivors $	(9) Rate %	(10) Survivor Factor
1	1	1,000.00	500.00	333.33	250.00	200.00	2,283.33	5,000.00	45.67	1.00
2	2		500.00	333.33	250.00	200.00	1,283.33	4,000.00	32.08	0.80
3	3			333.33	250.00	200.00	783.33	3,000.00	26.11	0.60
4	4				250.00	200.00	450.00	2,000.00	22.50	0.40
5	5					200.00	200.00	1,000.00	20.00	0.20
6	Retirements	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00				
7	Frequency	0.20	0.20	0.20	0.20	0.20				
8	Rate	100%	50%	33.33%	25%	20%				

$$\text{Rate, \%} = \frac{\dfrac{\text{Retirements Frequencies}}{\text{Age at Retirement}}}{\text{Reverse of Retirement Frequencies}} \times 100$$

$$\text{Year One Rate} = \frac{\dfrac{0.2}{1} + \dfrac{0.2}{2} + \dfrac{0.2}{3} + \dfrac{0.2}{4} + \dfrac{0.2}{5}}{0.2 + 0.2 + 0.2 + 0.2 + 0.2} \times 100 = 45.67\%$$

$$\text{Year Three Rate} = \frac{\dfrac{0.2}{3} + \dfrac{0.2}{4} + \dfrac{0.2}{5}}{0.2 + 0.2 + 0.2} \times 100 = 26.11\%$$

DETERMINATION OF DEPRECIATION RATES BY ELG PROCEDURES

[1] Age Years	[2] Year	[3] Vintage Balance $	[4] Retirement Frequency ASL 38 Curve L5	[5] Rate	[6] Amount $
0.5	1993	4,244,285	0.0000	0.02704	114,758.36
1.5	1992	800,784	0.0000	0.02704	21,651.86
2.5	1991	60,016	0.0000	0.02704	1,622.73
3.5	1990	43,455,063	0.0000	0.02704	1,174,952.00
4.5	1989	81,456	0.0000	0.02704	2,202.43
5.5	1988	172,463	0.0000	0.02704	4,663.11
6.5	1987	2,098,991	0.0000	0.02704	56,753.20
7.5	1986	2,685,949	0.0000	0.02704	72,623.55
9.5	1984	1,642,443	0.0000	0.02704	44,408.90
10.5	1983	222,602	0.0000	0.02704	6,018.78
11.5	1982	85,661	0.0000	0.02704	2,316.13
12.5	1981	4,985	0.0000	0.02704	134.79
13.5	1980	72,942	0.0000	0.02704	1,972.23
14.5	1979	219,163	0.0000	0.02704	5,925.80
15.5	1978	120,665	0.0000	0.02704	3,262.58
16.5	1977	37,042	0.0000	0.02704	1,001.55
17.5	1976	339,236	0.0000	0.02704	9,172.21
19.5	1974	336,723	0.0001	0.02703	9,101.41
20.5	1973	10,375,359	0.0004	0.02702	280,292.86
21.5	1972	4,481,906	0.0009	0.02699	120,963.25
22.5	1971	5,923,340	0.0018	0.02695	159,618.98
23.5	1970	78,848	0.0030	0.02689	2,119.97
24.5	1969	305,178	0.0047	0.02681	8,180.42
25.5	1968	10,312,586	0.0069	0.02670	275,375.94
26.5	1967	2,754,067	0.0094	0.02658	73,203.24
27.5	1966	9,558,786	0.0123	0.02644	252,715.77
29.5	1964	5,556,083	0.0194	0.02610	144,995.54
30.5	1963	23,383	0.0242	0.02589	605.42
31.5	1962	3,313,564	0.0305	0.02566	85,012.50
32.5	1961	32,271	0.0386	0.02538	819.15
33.5	1960	151,658	0.0482	0.02507	3,802.24
34.5	1959	171,483	0.0583	0.02472	4,238.70
35.5	1958	167,116	0.0674	0.02433	4,065.35
36.5	1957	70,420	0.0740	0.02390	1,683.22
37.5	1956	1,792,312	0.0768	0.02345	42,036.33
39.5	1954	2,270,555	0.0701	0.02252	51,131.79
40.5	1953	187	0.0622	0.02206	4.13
41.5	1952	20,185	0.0531	0.02161	436.14
42.5	1951	12,860	0.0442	0.02118	272.40
43.5	1950	706	0.0362	0.02078	14.67
44.5	1949	2,652	0.0296	0.02041	54.13
45.5	1948	6,422	0.0245	0.02006	128.81
46.5	1947	19,573	0.0205	0.01972	386.07
47.5	1946	323,058	0.0173	0.01940	6,268.69
49.5	1944	2,285,041	0.0123	0.01879	42,943.47
50.5	1943	15,614	0.0103	0.01850	288.86
51.5	1942	620,752	0.0085	0.01821	11,306.36
53.5	1940	684,610	0.0055	0.01766	12,090.28
54.5	1939	47,173	0.0043	0.01740	820.76
55.5	1938	22,725	0.0033	0.01714	389.52
56.5	1937	560	0.0025	0.01689	9.46
57.5	1936	722	0.0019	0.01664	12.02
59.5	1934	3,065	0.0005	0.01573	48.21
61.5	1932	944,400	0.0005	0.01573	14,853.98
67.5	1926	2	0.0000	0.01471	0.03
Totals		119,029,691			3,133,730.27
			SALVAGE (%) =		-5.0
			AFTER SALVAGE =		3,290,417
		ANNUAL DEPRECIATION RATE =			2.76