

ATMOS ENERGY CORP
Form 10-K
November 19, 2008

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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549**

Form 10-K

(Mark One)

- ☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
EXCHANGE ACT OF 1934**
For the fiscal year ended September 30, 2008
- OR**
- ☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

Texas and Virginia
*(State or other jurisdiction of
incorporation or organization)*
Three Lincoln Centre, Suite 1800
5430 LBJ Freeway, Dallas, Texas
(Address of principal executive offices)

75-1743247
*(IRS employer
identification no.)*
75240
(Zip code)

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2008, was \$2,243,034,264.

As of November 12, 2008, the registrant had 91,133,742 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 4, 2009 are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
ATO	Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
FSP	FASB Staff Position
GRIP	Gas Reliability Infrastructure Program
Heritage	Heritage Propane Partners, L.P.
iFERC	Inside FERC
KPSC	Kentucky Public Service Commission
LPSC	Louisiana Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
MPSC	Mississippi Public Service Commission
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
Settled Cities	Represents 438 of the 439 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
SFAS	Statement of Financial Accounting Standards
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
USP	U.S. Propane, L.P.
VCC	Virginia Corporation Commission
WNA	Weather Normalization Adjustment

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PART I

The terms we, our, us and Atmos Energy refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. Since our incorporation in Texas in 1983, we have grown primarily through a series of acquisitions, the most recent of which was the acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company. We are also incorporated in the state of Virginia.

Today, we distribute natural gas through regulated sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers in 12 states located primarily in the South, which makes us one of the country's largest natural-gas-only distributors based on number of customers. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation along with storage services to certain of our natural gas distribution divisions and third parties.

Our overall strategy is to:

deliver superior shareholder value,

improve the quality and consistency of earnings growth, while operating our regulated and nonregulated businesses exceptionally well and

enhance and strengthen a culture built on our core values.

We have experienced more than 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. Historically, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology, such as our 24-hour call centers, to achieve more efficient operations. In recent years, we have also achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations. Finally, we have strengthened our nonregulated businesses by increasing sales volumes and actively pursuing opportunities to increase the amount of storage available to us.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

Operating Segments

We operate the Company through the following four segments:

The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.

The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline Texas Division.

The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.

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The *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas transmission and storage services.

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment consists of the following six regulated divisions, in order of total customers served, covering service areas in 12 states:

Atmos Energy Mid-Tex Division,

Atmos Energy Kentucky/Mid-States Division,

Atmos Energy Louisiana Division,

Atmos Energy West Texas Division,

Atmos Energy Mississippi Division and

Atmos Energy Colorado-Kansas Division

Our natural gas distribution business is a seasonal business. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, we transport natural gas for others through our distribution system.

Rates established by regulatory authorities often include cost adjustment mechanisms that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

Purchased gas mechanisms represent a common form of cost adjustment mechanism. Purchased gas adjustment mechanisms provide natural gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in natural gas distribution gas costs. Therefore, although substantially all of our natural gas distribution operating revenues fluctuate with the cost of gas that we purchase, natural gas distribution gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial instruments to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

Finally, regulatory authorities for over 90 percent of residential and commercial meters in our service areas have approved weather normalization adjustments (WNA) as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

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As of September 30, 2008 we had WNA for our residential and commercial meters in the following service areas for the following periods:

Georgia	October	May
Kansas	October	May
Kentucky	November	April
Louisiana	December	March
Mississippi	November	April
Tennessee	November	April
Texas: Mid-Tex	November	April
Texas: West Texas	October	May
Virginia	January	December

In addition to seasonality, financial results for this segment are affected by the cost of natural gas and economic conditions in the areas that we serve. Higher gas costs, which we are generally able to pass through to our customers under purchased gas adjustment clauses, may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

Our supply of natural gas is provided by a variety of suppliers, including independent producers, marketers and pipeline companies and withdrawals of gas from proprietary and contracted storage assets. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements.

Supply arrangements are contracted from our suppliers on a firm basis with various terms at market prices. The firm supply consists of both base load and swing supply (peaking) quantities. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions.

Currently, all of our natural gas distribution divisions, except for our Mid-Tex Division, utilize 37 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have pipeline no-notice storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered by our Atmos Pipeline Texas Division.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers during fiscal 2008 were Anadarko Energy Services, BP Energy Company, Chesapeake Energy Marketing, Inc., ConocoPhillips Company, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., National Fuel Marketing Company, LLC, ONEOK Energy Services Company L.P., Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.2 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2008 was on January 2, 2008, when sales to

customers reached approximately 3.1 Bcf.

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state statutes or regulations. Our customers' demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis

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and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We anticipate no problems with obtaining additional gas supply as needed for our customers.

The following briefly describes our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2008, we held 1,107 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption Operating Statistics .

Atmos Energy Mid-Tex Division. Our Mid-Tex Division serves approximately 550 incorporated and unincorporated communities in the north-central, eastern and western parts of Texas, including the Dallas/Fort Worth Metroplex. The governing body of each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. The Railroad Commission of Texas (RRC) has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality.

Prior to fiscal 2008, this division operated under one system-wide rate structure. However, beginning in 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that will allow us to update rates for customers in these cities through an annual rate review mechanism. Rates for the remaining 20 percent of this division's customers, including the City of Dallas, continue to be updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division operates in more than 420 communities across Georgia, Illinois, Iowa, Kentucky, Missouri, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee, and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

Atmos Energy Louisiana Division. In Louisiana, we serve nearly 300 communities, including the suburban areas of New Orleans, the metropolitan area of Monroe and western Louisiana. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our natural gas marketing segment. Our rates in this division are updated annually through a stable rate filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, during 2008, the West Texas Division entered into agreements with its Lubbock and West Texas service areas to update rates for customers in these service areas through an annual rate review mechanism. Rates for the division's Amarillo service area continue to be updated through periodic formal rate proceedings and filings made under GRIP.

Atmos Energy Mississippi Division. In Mississippi, we serve about 110 communities throughout the northern half of the state, including the Jackson metropolitan area. Our rates in the Mississippi Division are updated annually through a stable rate filing without filing a formal rate case.

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Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division serves approximately 170 communities throughout Colorado and Kansas and parts of Missouri, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, a suburb of Denver. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

The following table provides a jurisdictional rate summary for our regulated operations. This information is for regulatory purposes only and may not be representative of our actual financial position.

			Effective Date of Last Rate/GRIP Action	Rate Base (thousands) ⁽¹⁾	Authorized Rate of Return ⁽¹⁾	Authorized Return on Equity ⁽¹⁾
Division		Jurisdiction				
Atmos Pipeline	Texas	Texas	5/24/04	\$417,111	8.258%	10.00%
Atmos Pipeline	Texas					
GRIP		Texas	4/15/08	713,351	8.258%	10.00%
Colorado-Kansas		Colorado	10/1/07	81,208	8.45%	11.25%
		Kansas	5/12/08	(2)	(2)	(2)
Kentucky/Mid-States		Georgia	9/22/08	66,893	7.75%	10.70%
		Illinois	11/1/00	24,564	9.18%	11.56%
		Iowa	3/1/01	5,000	(2)	11.00%
		Kentucky	8/1/07	(2)	(2)	(2)
		Missouri	3/4/07	(2)	(2)	(2)
		Tennessee	11/4/07	186,506	8.03%	10.48%
					8.46% -	9.50% -
		Virginia	9/30/08	33,194	8.96%	10.50%
						10.00% -
Louisiana		Trans LA	4/1/08	96,834	(2)	10.80%
		LGS	7/1/08	221,970	(2)	10.40%
Mid-Tex	Settled Cities	Texas	11/1/08	1,176,453 ⁽³⁾	7.79%	9.60%
Mid-Tex	Dallas &					
Environs		Texas	6/24/08	1,127,924 ⁽³⁾	7.98%	10.00%
Mississippi		Mississippi	12/28/07	215,117	7.60%	9.89%
West Texas		Amarillo	9/1/03	36,844	9.88%	12.00%
		Lubbock	3/1/04	43,300	9.15%	11.25%
		West Texas	11/18/08	112,043	7.79%	9.60%

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Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider⁽⁴⁾	WNA	Performance- Based Rate Program⁽⁵⁾	Customer Meters
Atmos Pipeline	Texas	Texas	50/50	No	N/A	N/A
Colorado-Kansas	Colorado	54/46	No	No	No	111,069
	Kansas	(2)	Yes	Yes	No	129,048
Kentucky/Mid-States	Georgia	55/45	No	Yes	Yes	69,043
	Illinois	67/33	No	No	No	23,233
	Iowa	57/43	No	No	No	4,425
	Kentucky	(2)	No	Yes	Yes	177,393
	Missouri	(2)	No	No ⁽⁶⁾	No	58,703
	Tennessee	56/44	Yes	Yes	Yes	134,128
	Virginia	55/45	Yes	Yes	No	23,422
Louisiana	Trans LA	52/48	No	Yes	No	78,867
	LGS	52/48	No	Yes	No	280,403
Mid-Tex	Settled Cities	Texas	52/48	Yes	Yes	No
Mid-Tex	Dallas & Environs	Texas	52/48	Yes	Yes	No
Mississippi	Mississippi	58/42	No ⁽⁷⁾	Yes	No	270,716
West Texas	Amarillo	50/50	Yes	Yes	No	70,157
	Lubbock	50/50	Yes	Yes	No	73,323
	West Texas	52/48	Yes	Yes	No	156,121

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the last rate case or GRIP filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas & Environs both represent system-wide, or 100 percent, of the Mid-Tex Division's rate base. The difference in rate base amounts is due to two separate test filing periods covered.

(4) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

(5) The performance-based rate program provides incentives to natural gas utility companies to minimize purchased gas costs by allowing the utility company and its customers to share the purchased gas costs savings.

(6) The Missouri jurisdiction has a straight-fixed variable rate design which decouples gross profit margin from customer usage patterns.

(7) The Company filed to amend its PGA rider to allow inclusion of bad debt costs on October 1, 2008.

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	Fiscal Year Ended September 30				
	2008	2007	2006	2005⁽¹⁾	2004
METERS IN SERVICE, end of year					
Residential	2,911,475	2,893,543	2,886,042	2,862,822	1,506,777
Commercial	268,845	272,081	275,577	274,536	151,381
Industrial	2,241	2,339	2,661	2,715	2,436
Public authority and other	9,218	19,164	16,919	17,767	18,542
Total meters	3,191,779	3,187,127	3,181,199	3,157,840	1,679,136
INVENTORY STORAGE BALANCE Bcf					
	58.3	58.0	59.9	54.7	27.4
HEATING DEGREE DAYS⁽²⁾					
Actual (weighted average)	2,820	2,879	2,527	2,587	3,271
Percent of normal	100%	100%	87%	89%	96%
SALES VOLUMES MMcf⁽³⁾					
Gas Sales Volumes					
Residential	163,229	166,612	144,780	162,016	92,208
Commercial	93,953	95,514	87,006	92,401	44,226
Industrial	21,734	22,914	26,161	29,434	22,330
Public authority and other	13,760	12,287	14,086	12,432	14,455
Total gas sales volumes	292,676	297,327	272,033	296,283	173,219
Transportation volumes	141,083	135,109	126,960	122,098	87,746
Total throughput	433,759	432,436	398,993	418,381	260,965
OPERATING REVENUES (000 \$)					
Gas Sales Revenues					
Residential	\$ 2,131,447	\$ 1,982,801	\$ 2,068,736	\$ 1,791,172	\$ 923,773
Commercial	1,077,056	970,949	1,061,783	869,722	400,704
Industrial	212,531	195,060	276,186	229,649	155,336
Public authority and other	137,821	114,298	144,600	114,742	109,029
Total gas sales revenues	3,558,855	3,263,108	3,551,305	3,005,285	1,588,842
Transportation revenues	60,504	59,813	62,215	59,996	31,714
Other gas revenues	35,771	35,844	37,071	37,859	17,172
Total operating revenues	\$ 3,655,130	\$ 3,358,765	\$ 3,650,591	\$ 3,103,140	\$ 1,637,728

Average transportation revenue per Mcf	\$	0.43	\$	0.44	\$	0.49	\$	0.49	\$	0.36
Average cost of gas per Mcf sold	\$	9.05	\$	8.09	\$	10.02	\$	7.41	\$	6.55
Employees		4,558		4,472		4,402		4,327		2,742

See footnotes following these tables.

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	Fiscal Year Ended September 30, 2008							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado- Kansas	Other ⁽⁴⁾	Total
RES IN								
CE								
tial	1,414,543	431,880	336,211	270,990	240,113	217,738		2,911,475
rcial	117,022	54,538	23,059	25,226	27,219	21,781		268,865
al	163	930		497	562	89		2,121
uthority and		2,563		2,888	2,822	945		9,328
	1,531,728	489,911	359,270	299,601	270,716	240,553		3,192,771
NG DEGREE								
)								
	2,213	3,799	1,531	3,546	2,741	5,861		20,731
of normal	99%	96%	99%	99%	101%	105%		20,731
VOLUMES								
)								
es Volumes								
tial	76,296	26,009	12,475	17,190	12,882	18,377		163,129
rcial	50,348	15,731	6,858	7,162	6,590	7,264		93,953
al	3,293	7,740		3,876	6,580	245		21,734
uthority and		1,419		6,933	3,013	2,395		13,760
	129,937	50,899	19,333	35,161	29,065	28,281		292,608
rtation volumes	49,606	44,796	6,136	26,411	4,219	9,915		141,073
roughput	179,543	95,695	25,469	61,572	33,284	38,196		433,769
ATING								
IN (000 \$)	\$ 478,622	\$ 159,265	\$ 110,754	\$ 87,344	\$ 91,749	\$ 78,332	\$	\$ 1,006,066
ATING								
SES (000 \$)								
on and								
ance	\$ 167,497	\$ 65,161	\$ 42,367	\$ 36,688	\$ 46,024	\$ 35,414	\$ (3,907)	\$ 385,143
ation and								
ation	\$ 84,202	\$ 30,574	\$ 21,193	\$ 14,781	\$ 11,752	\$ 14,703	\$	\$ 178,105
other than								
	\$ 111,914	\$ 14,799	\$ 8,104	\$ 22,032	\$ 14,003	\$ 7,600	\$	\$ 178,452
ATING								
IE (000 \$)	\$ 115,009	\$ 48,731	\$ 39,090	\$ 13,843	\$ 19,970	\$ 20,615	\$ 3,907	\$ 261,165
AL	\$ 178,409	\$ 59,274	\$ 46,674	\$ 34,354	\$ 22,590	\$ 20,331	\$ 24,910	\$ 386,531
IDITURES								

PROPERTY, PLANT

EQUIPMENT,

(in thousands) \$ 1,491,188 \$ 689,109 \$ 370,751 \$ 278,326 \$ 254,452 \$ 272,121 \$ 127,609 \$ 3,483

See footnotes following these tables.

DEPRECIATION, at year

Depreciation of pipe 28,697 12,104 8,277 14,697 6,537 7,150 77
 Depreciation of other equipment 1,506 635 427 342 393 281 974 4

See footnotes following these tables.

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	Fiscal Year Ended September 30, 2007							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado- Kansas	Other ⁽⁴⁾	Total
RES IN								
CE								
tial	1,398,274	434,529	334,467	270,557	240,073	215,643		2,893,543
rcial	119,660	54,964	23,015	25,460	27,461	21,521		272,081
al	185	927		521	619	87		2,139
uthority and		2,623		12,825	2,827	889		19,000
	1,518,119	493,043	357,482	309,363	270,980	238,140		3,187,085
NG DEGREE								
)								
	2,332	3,831	1,638	3,537	2,759	5,732		20,000
of normal	100%	97%	105%	99%	101%	104%		
VOLUMES								
)								
es Volumes								
tial	78,140	25,900	13,292	18,882	13,314	17,084		166,612
rcial	50,752	16,137	7,138	7,671	6,859	6,957		95,514
al	3,946	7,439		3,521	7,672	336		22,973
uthority and		1,454		5,376	3,386	2,071		12,313
	132,838	50,930	20,430	35,450	31,231	26,448		299,327
rtation volumes	49,337	46,852	6,841	21,709	2,072	8,298		135,039
roughput	182,175	97,782	27,271	57,159	33,303	34,746		432,436
ATING								
IN (000 \$)	\$ 433,279	\$ 151,442	\$ 108,908	\$ 90,285	\$ 94,866	\$ 73,904	\$	\$ 952,684
ATING								
SES (000 \$)								
on and								
ance	\$ 171,416	\$ 61,029	\$ 34,805	\$ 34,187	\$ 47,318	\$ 30,026	\$ 394	\$ 379,165
ation and	\$ 82,524	\$ 34,439	\$ 20,941	\$ 14,026	\$ 10,886	\$ 14,372	\$	\$ 177,188
ation	\$ 107,476	\$ 13,813	\$ 8,969	\$ 21,036	\$ 13,437	\$ 7,114	\$	\$ 172,845
other than	\$ 3,289	\$	\$	\$	\$	\$	\$	\$ 3,289
ent of								
ed assets	\$ 68,574	\$ 42,161	\$ 44,193	\$ 21,036	\$ 23,225	\$ 22,392	\$ (394)	\$ 223,625
ATING	\$ 140,037	\$ 59,641	\$ 40,752	\$ 27,031	\$ 20,643	\$ 21,395	\$ 17,943	\$ 327,442
IE (000 \$)								
AL								
IDITURES								

PROPERTY, PLANT

EQUIPMENT,

(in thousands) \$ 1,356,453 \$ 656,920 \$ 345,535 \$ 258,622 \$ 241,796 \$ 264,629 \$ 127,189 \$ 3,251,000

AND

DEPRECIATION, at year

of pipe	28,324	12,081	8,216	14,603	6,496	6,642		70,000
tees	1,415	633	422	340	409	269	984	4,000

Notes to preceding tables:

- (1) The operational and statistical information includes the operations of the Mid-Tex Division since the October 1, 2004 acquisition date.
- (2) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.
- (3) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.
- (4) The Other column represents our shared services function, which provides administrative and other support to the Company. Certain costs incurred by this function are not allocated.

Table of Contents**Regulated Transmission and Storage Segment Overview**

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. However, Atmos Pipeline Texas existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

Regulated Transmission and Storage Sales and Statistical Data

	Fiscal Year Ended September 30				
	2008	2007	2006	2005	2004⁽¹⁾
CUSTOMERS, end of year					
Industrial	62	65	67	66	
Other	189	196	178	191	
Total	251	261	245	257	
PIPELINE TRANSPORTATION					
VOLUMES MMcf	782,876	699,006	581,272	554,452	
OPERATING REVENUES (000 \$)	\$ 195,917	\$ 163,229	\$ 141,133	\$ 142,952	
Employees, at year end	60	54	85	78	

(1) Atmos Pipeline Texas was acquired on October 1, 2004, the first day of our 2005 fiscal year.

(2) Transportation volumes and operating revenues reflect segment operations, including intercompany sales and transportation amounts.

Natural Gas Marketing Segment Overview

Our natural gas marketing activities are conducted through Atmos Energy Marketing (AEM), which is wholly-owned by Atmos Energy Holdings, Inc. (AEH). AEH is a wholly-owned subsidiary of AEC and operates primarily in the Midwest and Southeast areas of the United States. AEM aggregates and purchases gas supply, arranges transportation and storage logistics and ultimately delivers gas to customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and

administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

Our asset optimization activities seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We

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purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Through the use of transportation and storage services and financial instruments, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM's management of natural gas requirements involves the sale of natural gas and the management of storage and transportation supplies under contracts with customers generally having one to two year terms. AEM also sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms ranging from 30 days to two years.

Natural Gas Marketing Sales and Statistical Data

	Fiscal Year Ended September 30				
	2008	2007	2006	2005	2004
CUSTOMERS, end of year					
Industrial	624	677	679	559	638
Municipal	55	68	73	69	80
Other	312	281	289	211	237
Total	991	1,026	1,041	839	955
INVENTORY STORAGE					
BALANCE Bcf	11.0	19.3	15.3	8.2	5.2
NATURAL GAS					
MARKETING SALES					
VOLUMES MMcf⁽¹⁾	457,952	423,895	336,516	273,201	265,090
OPERATING REVENUES					
(000 \$)⁽¹⁾	\$ 4,287,862	\$ 3,151,330	\$ 3,156,524	\$ 2,106,278	\$ 1,618,602

⁽¹⁾ Sales volumes and operating revenues reflect segment operations, including intercompany sales and transportation amounts.

Pipeline, Storage and Other Segment Overview

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH.

APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM. However, it also provides limited third party transportation services. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Finally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of September 30, 2008, these activities were limited in nature.

APS also engages in limited asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Most of these arrangements are with regulated affiliates of the Company and have been approved by applicable state regulatory commissions. Generally, these arrangements require APS to share with our regulated customers a portion of the profits earned from these arrangements.

AES, through December 31, 2006, provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our natural gas distribution service areas at competitive prices. Effective January 1, 2007, our shared services function began

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providing these services to our natural gas distribution operations. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Pipeline, Storage and Other Sales and Statistical Data

		Fiscal Year Ended September 30			
	2008	2007	2006	2005	2004
OPERATING REVENUES (000 \$)	\$ 31,709	\$ 33,400	\$ 25,574	\$ 15,639	\$ 23,151
PIPELINE TRANSPORTATION VOLUMES MMcf⁽¹⁾	5,492	7,710	9,712	7,593	9,395
INVENTORY STORAGE BALANCE Bcf	1.4	2.0	2.6	1.8	2.3

⁽¹⁾ Transportation volumes and operating revenues reflect segment operations, including intercompany sales and transportation amounts.

Ratemaking Activity***Overview***

The method of determining regulated rates varies among the states in which our natural gas distribution divisions operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital.

Our current rate strategy is to focus on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins. Atmos Energy has annual ratemaking mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately 65 percent of our customers. Additionally, we have WNA mechanisms in eight states. These mechanisms work in tandem to provide insulation from volatile margins, both for the Company and our customers.

We will also continue to address various rate design changes, including the recovery of bad debt gas costs, inclusion of other taxes in gas costs and stratification of rates to benefit low income households in future rate filings. These design changes would address cost variations that are related to pass-through energy costs beyond our control.

Improving rate design is a long-term process. In the interim, we are addressing regulatory lag issues by directing discretionary capital spending to jurisdictions where recovery rules minimize the regulatory lag, which helps us to keep actual returns more closely aligned with allowed returns.

Table of Contents***Recent Ratemaking Activity***

Approximately 97 percent of our natural gas distribution revenues in the fiscal years ended September 30, 2008, 2007 and 2006 were derived from sales at rates set by or subject to approval by local or state authorities. Net annual revenue increases resulting from ratemaking activity totaling \$34.5 million, \$40.1 million, and \$39.0 million became effective in fiscal 2008, 2007 and 2006 as summarized below:

Rate Action	Increase (Decrease) to Revenue For the Fiscal Year Ended September 30		
	2008	2007	2006
	(In thousands)		
Rate case filings	\$ 22,240	\$ 4,221	\$ (191)
GRIP filings	8,101	25,624	34,320
Annual rate filing mechanisms	3,775	11,628	3,326
Other rate activity	334	(1,359)	1,565
	\$ 34,450	\$ 40,114	\$ 39,020

Additionally, the following ratemaking efforts were initiated during fiscal 2008 but had not been completed as of September 30, 2008:

Division	Rate Action	Jurisdiction	Revenue Requested (In thousands)
Mid-Tex ⁽¹⁾	RRM	Settled Cities	\$ 26,650
Mid-Tex ⁽²⁾	GRIP	Dallas & Environs	1,837
West Texas ⁽³⁾	RRM	West Texas	9,503
Mississippi	Stable Rate Filing	Mississippi	3,493
West Texas	CCVP	City of Lubbock	131
			\$ 41,614

⁽¹⁾ In April 2008, the Mid-Tex Division filed its first RRM that will adjust rates for the 438 incorporated cities in the division who settled with the Company (the Settled Cities). The filing requested an increase in rates of \$33.3 million on a system-wide basis, of which \$26.7 million applied to the Settled Cities. The Company reached an agreement with representatives of the Settled Cities to increase rates \$20.0 million on a system-wide basis beginning in November 2008. The impact to the Mid-Tex Division for the Settled Cities is approximately \$16.0 million.

⁽²⁾ The 2007 Mid-Tex GRIP filing seeks a \$10.3 million increase on a system-wide basis. However, this filing was only made for the City of Dallas and the Mid-Tex environs and seeks a \$1.8 million increase for customers in those service areas only.

- (3) The Company reached an agreement with representatives of the West Texas Cities to increase rates a total of \$3.9 million. The \$3.9 million will be collected through the true-up portion of the RRM tariff rates over a 9 1/2 month period beginning in November 2008.

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Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase (Decrease) in Annual Revenue (In thousands)	Effective Date
<i>2008 Rate Case Filings:</i>			
Kentucky/Mid-States	Virginia	\$ 869	9/30/08
Kentucky/Mid-States	Georgia	3,351	9/22/08
Mid-Tex ⁽¹⁾	Texas	3,930	6/24/08
Colorado-Kansas	Kansas	2,100	5/12/08
Mid-Tex ⁽²⁾	Texas	8,000	4/1/08
Kentucky/Mid-States	Tennessee	3,990	11/4/07
Total 2008 Rate Case Filings		\$ 22,240	
<i>2007 Rate Case Filings:</i>			
Kentucky/Mid-States	Kentucky ⁽³⁾	\$ 5,500	8/1/07
Mid-Tex	Texas ⁽⁴⁾	4,793	4/1/07
Kentucky/Mid-States	Missouri ⁽⁵⁾		3/4/07
Kentucky/Mid-States	Tennessee	(6,072)	12/15/06
Total 2007 Rate Case Filings		\$ 4,221	
<i>2006 Rate Case Filings:</i>			
Kentucky/Mid-States	Georgia	\$ 409	11/22/05
Mississippi	Mississippi	(600)	10/1/05
Total 2006 Rate Case Filings		\$ (191)	

⁽¹⁾ In June 2008, the RRC issued an order, which increased the Mid-Tex Division's annual revenues by \$19.6 million on a system-wide basis beginning in July 2008. However, as the increase only relates to the City of Dallas and the unincorporated areas of the Mid-Tex Division, the net annual impact of the implementation is approximately \$3.9 million.

⁽²⁾

In April 2008, the Mid-Tex Division implemented new rates based on a settlement reached with the Mid-Tex Settled Cities, which stipulated a \$10.0 million increase based on a system-wide basis. However, as the increase only relates to the Settled Cities, the net annual impact of the implementation is approximately \$8.0 million.

- (3) In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. In June 2007, the KPSC issued an order dismissing the case. In December 2006, the Company filed a rate application for an increase in base rates. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. In July 2007, the KPSC approved a settlement we had reached with the Attorney General for an increase in annual revenues of \$5.5 million effective August 1, 2007.
- (4) In March 2007, the RRC issued an order, which increased the Mid-Tex Division's annual revenues by approximately \$4.8 million beginning April 2007 and established a permanent WNA based on 10-year average weather effective for the months of November through April of each year. The RRC also approved

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a cost allocation method that eliminated a subsidy received from industrial and transportation customers and increased the revenue responsibility for residential and commercial customers. However, the order also required an immediate refund of amounts collected from our 2003 – 2005 GRIP filings of approximately \$2.9 million and reduced our total return to 7.903 percent from 8.258 percent, based on a capital structure of 48.1 percent equity and 51.9 percent debt with a return on equity of 10 percent.

- (5) The Missouri Commission issued an order in March 2007 approving a settlement with rate design changes, including revenue decoupling through the recovery of all non-gas cost revenues through fixed monthly charges and no rate increase.

GRIP Filings

As discussed above in Natural Gas Distribution Segment Overview, GRIP allows natural gas utility companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. The following table summarizes our GRIP filings with effective dates during the fiscal years ended September 30, 2008, 2007 and 2006:

Division	Calendar Year	Incremental Net Utility Plant Investment (In thousands)	Additional Annual Revenue (In thousands)	Effective Date
<i>2008 GRIP:</i>				
Atmos Pipeline Texas	2007	\$ 46,648	\$ 6,970	4/15/08
West Texas	2006	7,022	1,131	12/17/07
Total 2008 GRIP		\$ 53,670	\$ 8,101	
<i>2007 GRIP:</i>				
Atmos Pipeline Texas	2006	\$ 88,938	\$ 13,202	9/14/07
Mid-Tex	2006	62,375	12,422	9/14/07
Total 2007 GRIP		\$ 151,313	\$ 25,624	
<i>2006 GRIP:</i>				
Mid-Tex ⁽¹⁾	2005	\$ 62,156	\$ 11,891	9/1/06
West Texas	2005	3,802		9/1/06
Atmos Pipeline Texas	2005	21,486	3,286	8/1/06
West Texas	2004	22,597	3,802	5/4/06
Mid-Tex ⁽¹⁾	2004	28,903	6,731	2/1/06
Atmos Pipeline Texas	2004	10,640	1,919	1/1/06
Mid-Tex ⁽¹⁾	2003	32,518	6,691	10/1/05
Total 2006 GRIP		\$ 182,102	\$ 34,320	

- (1) The order issued by the RRC in the Mid-Tex rate case required an immediate refund of amounts collected from the Mid-Tex Division's 2003-2005 GRIP filings of approximately \$2.9 million. This refund is not reflected in the amounts shown in the table above.

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As discussed above in Natural Gas Distribution Segment Overview, we currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas

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Divisions and stable rate filings in our Louisiana and Mississippi divisions. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Additional Annual Revenue (In thousands)	Effective Date
<i>2008 Filings:</i>				
Louisiana	LGS	12/31/07	\$ 1,709	7/1/08
Louisiana	Transla	9/30/07	2,066	4/1/08
Total 2008 Filings			\$ 3,775	
<i>2007 Filings:</i>				
Mississippi	Mississippi	6/30/07	\$	11/1/07
Louisiana	LGS	12/31/06	665	7/1/07
Louisiana	Transla	9/30/06	1,445	4/1/07
Louisiana	LGS	12/31/05	9,518	8/1/06
Total 2007 Filings			\$ 11,628	
<i>2006 Filings:</i>				
Mississippi	Mississippi	6/30/06	\$	11/1/06
Louisiana	LGS	12/31/03	3,326	2/1/06
Total 2006 Filings			\$ 3,326	

The rate review mechanism in the Mid-Tex Division was entered into as a result of a settlement in the September 20, 2007 Statement of Intent case filed with all Mid-Tex Division cities. Of the 439 incorporated cities served by the Mid-Tex Division, 438 of these cities are part of the rate review mechanism process. The West Texas rate review mechanism was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock Customer Conservation Value Plan (CCVP) was entered into in May 2008 as a result of a settlement to resolve ongoing rate issues. All three mechanisms have been implemented under a three year trial basis, beginning in fiscal 2009, based upon calendar 2007 financial information.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2008, 2007 and 2006:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Revenue	Effective Date
-----------------	---------------------	----------------------	---------------------------------------	-----------------------

(In thousands)				
<i>2008 Other Rate Activity:</i>				
Colorado-Kansas	Kansas	Ad Valorem Tax ⁽¹⁾	\$ 1,434	1/1/08
Colorado-Kansas	Colorado	Earnings Agreement ⁽²⁾	(1,100)	11/20/07
Total 2008 Other Rate Activity			\$ 334	
<i>2007 Other Rate Activity:</i>				
Mid-Tex	Texas	GRIP Refund	\$ (2,887)	4/1/07
Colorado-Kansas	Kansas	Ad Valorem Tax ⁽¹⁾	1,528	1/1/07
Total 2007 Other Rate Activity			\$ (1,359)	
<i>2006 Other Rate Activity:</i>				
Colorado-Kansas	Kansas	Ad Valorem Tax ⁽¹⁾	\$ 1,565	1/1/06
Total 2006 Other Rate Activity			\$ 1,565	

See footnotes on the following page.

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- (1) In the state of Kansas, ad valorem tax represents a general tax on all real and personal property determined based on the value of the property. This tax is assessed to the Company and recovered from our customers through our rates.
- (2) In November 2007, the Colorado Public Utilities Commission approved an earnings agreement entered into jointly between the Colorado-Kansas Division, the Commission Staff and the Office of Consumer Counsel. The agreement called for a one-time refund to customers of \$1.1 million made in January 2008.

In addition to the activity above, in December 2006, the Louisiana Public Service Commission issued a staff report allowing the deferral of \$4.3 million in operating and maintenance expenses in our Louisiana Division to allow recovery of all incremental operation and maintenance expense incurred in fiscal 2005 and 2006 in connection with our Hurricane Katrina recovery efforts.

In September 2006, our Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately \$24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division received approval to refund these amounts over a six-month period, which began in November 2006. The ruling had no impact on the gross profit for the Mid-Tex Division.

In May 2007, our Mid-Tex Division filed a 36-month gas contract review filing. This filing is mandated by prior RRC orders and relates to the prudence of gas purchases made from November 2003 through October 2006, which total approximately \$2.7 billion. An agreed-upon procedural schedule was filed with the RRC, which established a hearing schedule beginning in December 2007. In July 2008, the City of Dallas filed testimony recommending a disallowance of approximately \$58 million and the ACSC Coalition of Cities filed testimony recommending a disallowance of approximately \$89 million. However, the Mid-Tex Division has historically been able to settle similar gas contract reviews for significantly less than the requested disallowance amounts. A hearing was held at the RRC in September 2008, and initial and reply briefs were filed by all parties in mid-October 2008. A proposal for decision on this matter is expected by the end of March 2009.

Other Regulation

Each of our natural gas distribution divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. In addition, our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with and are operated in substantial conformity with applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites in Tennessee, Iowa and Missouri.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline Texas assets on behalf of interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC.

The RRC has issued a final rule requiring the replacement of known compression couplings at pre-bent gas meter risers by November 2009. This rule affects the operations of the Mid-Tex Division but is presently not anticipated to have a significant impact on our West Texas Division. This rule requires us to expend significant amounts of capital in

the Mid-Tex Division, but these prudent and mandatory expenditures should be recoverable through our rates.

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Competition

Although our natural gas distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. However, higher gas prices, coupled with the electric utilities' marketing efforts, have increased competition for residential and commercial customers. In addition, AEM competes with other natural gas marketers to provide natural gas management and other related services to customers.

Our regulated transmission and storage operations currently face limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers.

Employees

At September 30, 2008, we had 4,750 employees, consisting of 4,618 employees in our regulated operations and 132 employees in our nonregulated operations.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, www.atmosenergy.com, under Publications and Filings under the Investors tab, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer, Robert W. Best, has certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

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ITEM 1A. Risk Factors.

Our financial and operating results are subject to a number of risk factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other or new risks may prove to be important in the future. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following:

The continuation of the unprecedented disruptions in the credit markets could limit our ability to access capital and increase our costs of capital.

We rely upon access to both short-term and long-term credit markets to satisfy our liquidity requirements. The global credit markets have been experiencing significant disruption and volatility in recent months, to a greater degree than has been seen in decades. In some cases, the ability or willingness of traditional sources of capital to provide financing has been reduced.

Historically, we have accessed the commercial paper markets to finance our short-term working capital needs. However, the disruptions in the credit markets since mid-September 2008 have limited our access to the commercial paper markets. Consequently, we have borrowed directly under our primary credit facility that backstops our commercial paper program to provide much of our working capital. This credit facility provides up to \$600 million in committed financing through its expiration in December 2011; however, one lender with a 5.55% share of the commitments has ceased funding, effectively reducing the facility's size to \$567 million. Our borrowings under this facility, along with our commercial paper, have been used primarily to purchase natural gas supply for the upcoming winter heating season. The amount of our working capital requirements in the near-term will depend primarily on the market price of natural gas. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations. The cost of both our borrowings under the primary credit facility and our commercial paper has increased significantly since mid-September 2008. We have historically supplemented our commercial paper program with a short-term committed credit facility that must be renewed annually. No borrowings are currently outstanding under this \$212.5 million facility, which matures at the end of October 2009.

Our long-term debt is currently rated as investment grade by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. If continuing adverse credit conditions cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. If we were to lose our investment-grade rating from any of the three credit rating agencies, we would lose our ability to issue unsecured long-term debt in the capital markets without further regulatory approval due to restrictions imposed by one of the state regulatory commissions that regulates our natural gas distribution business. Additionally, such a downgrade could even further limit our access to private credit markets and increase the costs of borrowing under credit lines that could be available.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our natural gas marketing segment because the commodity financial instruments markets could become unavailable to us. Our natural gas marketing segment depends primarily upon an uncommitted demand \$580 million credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. Although the availability of credit under this facility has not yet been affected, the continuation of current market conditions could adversely affect such availability. A significant reduction in such availability could require us to provide extra liquidity to support its operations or reduce some of the activities of our natural gas marketing segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

A continuation of the recent deterioration in credit markets could also adversely impact our plans to refinance debt that matures at the beginning of fiscal 2010. We financed our TXU Gas acquisition in October 2004 in part with the proceeds of our 4% senior notes due 2009. The \$400 million principal amount of these

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notes matures in October 2009 and we plan to access the capital markets to refinance this debt prior to maturity. A continuation of current market conditions could adversely affect the cost or other terms of such refinancing.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results of a continuation of current market conditions could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in avoiding a recession or in lessening the severity or duration of a recession. As a result, our customers may seek to use less gas in upcoming heating seasons and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results.

We provide a cash-balance pension plan and postretirement healthcare benefits to eligible full-time employees. Our costs of providing such benefits and related funding requirements are subject to changes in the market value of the assets funding our pension and postretirement healthcare plans. The recent significant decline in the value of investments that fund our pension and postretirement healthcare plans may significantly differ from or alter the values and actuarial assumptions we use to calculate our future pension plan expense and postretirement healthcare costs. A continuation or further decline in the value of these investments could increase the expenses of our pension and postretirement healthcare plans and related funding requirements in the future. Our costs of providing such benefits and related funding requirements are also subject to changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years, as well as various actuarial calculations and assumptions, which may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and interest rates and other factors.

Our operations are exposed to market risks that are beyond our control which could adversely affect our financial results and capital requirements.

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility and counterparty creditworthiness. Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices or the risk in our natural gas marketing and pipeline, storage and other segments, which could lead to volatility in our earnings. Physical trading also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. The determination of our net open position as of the end of any particular trading day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to

our anticipated storage and market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Net open positions may increase volatility in our financial condition or results of

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operations if market prices move in a significantly favorable or unfavorable manner because the timing of the recognition of profits or losses on the hedges for financial accounting purposes usually do not match up with the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Further, if the local physical markets in which we trade do not move consistently with the NYMEX futures market, we could experience increased volatility in the financial results of our natural gas marketing and pipeline, storage and other segments.

Our natural gas marketing and pipeline, storage and other segments manage margins and limit risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial instruments. However, contractual limitations could adversely affect our ability to withdraw gas from storage, which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We could also realize financial losses on our efforts to limit risk as a result of volatility in the market prices of the underlying commodities or if a counterparty fails to perform under a contract. A continued tightening of the credit market could cause more of our counterparties to fail to perform than expected and reserved. In addition, adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract. These circumstances could also increase our capital requirements.

We are also subject to interest rate risk on our borrowings. In recent years, we have been operating in a relatively low interest-rate environment with both short and long-term interest rates being relatively low compared to historical interest rates. However, increases in interest rates could adversely affect our future financial results.

We are subject to state and local regulations that affect our operations and financial results.

Our natural gas distribution and regulated transmission and storage segments are subject to various regulated returns on our rate base in each jurisdiction in which we operate. We monitor the allowed rates of return and our effectiveness in earning such rates and initiate rate proceedings or operating changes as we believe are needed. In addition, in the normal course of business in the regulatory environment, assets may be placed in service and historical test periods established before rate cases can be filed that could result in an adjustment of our returns. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as regulatory lag. Rate cases also involve a risk of rate reduction, because once rates have been approved, they are still subject to challenge for their reasonableness by appropriate regulatory authorities. In addition, regulators may review our purchases of natural gas and can adjust the amount of our gas costs that we pass through to our customers. Finally, our debt and equity financings are also subject to approval by regulatory bodies in several states, which could limit our ability to access or take advantage of changes in the capital markets.

Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results.

FERC has regulatory authority that affects some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. We are currently under investigation by FERC for possible violations of FERC's posting and competitive bidding regulations for pre-arranged released firm capacity on interstate natural gas pipelines. Although we are currently taking action to

structure current and future transactions to comply with applicable FERC regulations, we are unable to predict the impact that these rules or any future regulatory activities of FERC and other federal agencies will have on our operations or financial results. Changes in regulations or their interpretation or additional regulations could adversely affect our business or financial results.

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We are subject to environmental regulations which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations. In addition, there are a number of new federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. Such revised or new regulations could result in increased compliance costs or additional operating restrictions which could adversely affect our business, financial condition or financial results.

The concentration of our distribution, pipeline and storage operations in the State of Texas exposes our operations and financial results to economic conditions and regulatory decisions in Texas.

As a result of our acquisition of the distribution, pipeline and storage operations of TXU Gas in October 2004, over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

Since the 2006-2007 winter heating season, we have had weather-normalized rates for over 90 percent of our residential and commercial meters, which has substantially mitigated the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our natural gas marketing operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our natural gas distribution gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. However, the ability to control expenses is an important factor that could impact future financial results.

Rapid increases in the costs of purchased gas, which has occurred in recent years, cause us to experience a significant increase in short-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts

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receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

We must continually build additional capacity in our natural gas distribution system to maintain the growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

In residential and commercial customer markets, our natural gas distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if, as a result, our customer growth slows, reducing our ability to make capital expenditures, or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage segment currently faces limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

Distributing and storing natural gas involve risks that may result in accidents and additional operating costs.

Our natural gas distribution business involves a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We do have liability and property insurance coverage in place for many of these hazards and risks. However, because our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our operations or financial results could be adversely affected.

Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may be more limited, which could increase the risk that an event could adversely affect our operations or financial results.

Table of Contents**ITEM 1B. *Unresolved Staff Comments.***

Not applicable.

ITEM 2. *Properties.***Distribution, transmission and related assets**

At September 30, 2008, our natural gas distribution segment owned an aggregate of 77,462 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Our regulated transmission and storage segment owned 6,069 miles of gas transmission and gathering lines and our pipeline, storage and other segment owned 114 miles of gas transmission and gathering lines.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf) ⁽¹⁾	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
<i>Natural Gas Distribution Segment</i>				
Kentucky	4,442,696	6,322,283	10,764,979	109,100
Kansas	3,239,000	2,300,000	5,539,000	45,000
Mississippi	2,211,894	2,442,917	4,654,811	48,000
Georgia	450,000	50,000	500,000	30,000
<i>Total</i>	10,343,590	11,115,200	21,458,790	232,100
<i>Regulated Transmission and Storage Segment</i>				
<i>Texas</i>	39,243,226	13,128,025	52,371,251	1,235,000
<i>Pipeline, Storage and Other Segment</i>				
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
<i>Total</i>	3,931,483	3,595,973	7,527,456	127,000
Total	53,518,299	27,839,198	81,357,497	1,594,100

⁽¹⁾ Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

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Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)⁽¹⁾
<i>Natural Gas Distribution Segment</i>			
	Colorado-Kansas Division	4,237,243	108,232
	Kentucky/Mid-States Division	15,301,017	287,798
	Louisiana Division	2,574,479	158,731
	Mississippi Division	4,033,649	168,039
	West Texas Division	1,225,000	56,000
<i>Total</i>		27,371,388	778,800
<i>Natural Gas Marketing Segment</i>	Atmos Energy Marketing, LLC	7,879,724	202,586
<i>Pipeline, Storage and Other Segment</i>	Trans Louisiana Gas Pipeline, Inc.	1,200,000	55,720
Total Contracted Storage Capacity		36,451,112	1,037,106

⁽¹⁾ Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

Other facilities

Our natural gas distribution segment owns and operates one propane peak shaving plant with a total capacity of approximately 180,000 gallons that can produce an equivalent of approximately 3,300 Mcf daily.

Offices

Our administrative offices and corporate headquarters are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. Our nonregulated operations are headquartered in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. Legal Proceedings.

See Note 12 to the consolidated financial statements.

ITEM 4. Submission of Matters to a Vote of Security Holders.

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2008.

Table of Contents**EXECUTIVE OFFICERS OF THE REGISTRANT**

The following table sets forth certain information as of September 30, 2008, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	61	11	Chairman, President and Chief Executive Officer
Kim R. Cocklin	57	2	Senior Vice President, Regulated Operations
Louis P. Gregory	53	8	Senior Vice President and General Counsel
Michael E. Haefner	48		Senior Vice President
Mark H. Johnson	49	7	Senior Vice President, Nonregulated Operations and President, Atmos Energy Marketing, LLC
Wynn D. McGregor	55	20	Senior Vice President, Human Resources
John P. Reddy	55	10	Senior Vice President and Chief Financial Officer

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997. Effective October 1, 2008, Mr. Best continues to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin joined the Company in June 2006 as Senior Vice President, Regulated Operations. On October 1, 2008, Mr. Cocklin was named President and Chief Operating Officer. Prior to joining the Company, Mr. Cocklin served as Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 to May 2006.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000.

Michael E. Haefner joined the Company in June 2008 as Senior Vice President to succeed Wynn D. McGregor, who retired from the Company on October 1, 2008. Prior to joining the Company, Mr. Haefner was a self-employed consultant and founder and president of Perform for Life, LLC from May 2007 to May 2008. Mr. Haefner previously served for 10 years as the Senior Vice President, Human Resources, of Sabre Holding Corporation, the parent company of Sabre Airline Solutions, Sabre Travel Network and Travelocity.

Mark H. Johnson was named Senior Vice President, Nonregulated Operations in April 2006 and President of Atmos Energy Holdings, Inc., and Atmos Energy Marketing, LLC, in April 2005. Mr. Johnson previously served the Company as Vice President, Nonutility Operations from October 2005 to March 2006 and as Executive Vice President of Atmos Energy Marketing from October 2003 to March 2005.

Wynn D. McGregor was named Senior Vice President, Human Resources in October 2005. He previously served the Company as Vice President, Human Resources from January 1994 to September 2005. Mr. McGregor retired from the Company on October 1, 2008.

John P. Reddy was named Senior Vice President and Chief Financial Officer in September 2000.

Table of Contents**PART II****ITEM 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Our stock trades on the New York Stock Exchange under the trading symbol ATO. The high and low sale prices and dividends paid per share of our common stock for fiscal 2008 and 2007 are listed below. The high and low prices listed are the closing NYSE quotes, as reported on the NYSE composite tape, for shares of our common stock:

	2008			2007		
	High	Low	Dividends paid	High	Low	Dividends paid
<u>Quarter Ended:</u>						
December 31	\$ 29.46	\$ 26.11	\$.325	\$ 33.01	\$ 28.45	\$.320
March 31	28.96	25.09	.325	33.00	30.63	.320
June 30	28.54	25.81	.325	33.11	29.38	.320
September 30	28.25	25.49	.325	30.66	26.47	.320
			\$ 1.30			\$ 1.28

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2008 was 21,825. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2008 that were not registered under the Securities Act of 1933, as amended.

Table of Contents**Performance Graph**

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor's 500 Stock Index and the cumulative total return of two different customized peer company groups, the New Comparison Company Index and the Old Comparison Company Index. The New Comparison Company Index includes Integrys Energy Group, Inc. because the Board of Directors determined that Integrys Energy Group, Inc. fits the profile of the companies in the peer group, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that \$100.00 was invested on September 30, 2003 in our common stock, the S&P 500 Index and in the common stock of the companies in the New and Old Comparison Company Indexes, as well as a reinvestment of dividends paid on such investments throughout the period.

**Comparison of Five-Year Cumulative Total Return
among Atmos Energy Corporation, S&P 500 Index
and Comparison Company Indices**

	Cumulative Total Return					
	9/30/03	9/30/04	9/30/05	9/30/06	9/30/07	9/30/08
Atmos Energy Corporation	100.00	110.52	129.67	137.30	141.91	139.94
S&P 500 Index	100.00	113.87	127.82	141.62	164.90	128.66
New Comparison Company Index	100.00	121.05	170.07	165.67	194.83	168.42
Old Comparison Company Index	100.00	121.42	171.06	167.35	197.75	168.15

The New Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by a global management consulting firm and approved by the Board of Directors. The companies included in the index are AGL Resources Inc., CenterPoint Energy Resources Corporation, CMS Energy Corporation, Equitable Resources, Inc., Integrys Energy Group, Inc., Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Questar Corporation, Vectren Corporation and WGL Holdings, Inc. The Old Comparison Company Index includes the companies listed above in the New Comparison Company Index with the exception of Integrys Energy Group, Inc., which was added to the Company's peer group in the current year for the reasons discussed above.

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The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2008.

	Number of Securities to be Issued	Weighted-Average	Number of Securities Remaining Available For Future Issuance Under Equity Compensation
	Upon Exercise of Outstanding Options, Warrants and Rights (a)	Exercise Price of Outstanding Options, Warrants and Rights (b)	Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan	913,841	\$ 22.54	2,122,776
Total equity compensation plans approved by security holders	913,841	22.54	2,122,776
Equity compensation plans not approved by security holders			
Total	913,841	\$ 22.54	2,122,776

Table of Contents**ITEM 6. Selected Financial Data.**

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Fiscal Year Ended September 30				
	2008	2007 ⁽¹⁾	2006 ⁽¹⁾	2005 ⁽²⁾	2004 ⁽³⁾
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	\$ 7,221,305	\$ 5,898,431	\$ 6,152,363	\$ 4,961,873	\$ 2,920,037
Gross profit	1,321,326	1,250,082	1,216,570	1,117,637	562,191
Operating expenses ⁽¹⁾	893,431	851,446	833,954	768,982	368,496
Operating income	427,895	398,636	382,616	348,655	193,695
Miscellaneous income ⁽³⁾	2,731	9,184	881	2,021	9,507
Interest charges	137,922	145,236	146,607	132,658	65,437
Income before income taxes	292,704	262,584	236,890	218,018	137,765
Income tax expense	112,373	94,092	89,153	82,233	51,538
Net income	\$ 180,331	\$ 168,492	\$ 147,737	\$ 135,785	\$ 86,227
Weighted average diluted shares outstanding	90,272	87,745	81,390	79,012	54,416
Diluted net income per share	\$ 2.00	\$ 1.92	\$ 1.82	\$ 1.72	\$ 1.58
Cash flows from operations	370,933	547,095	311,449	386,944	270,734
Cash dividends paid per share	\$ 1.30	\$ 1.28	\$ 1.26	\$ 1.24	\$ 1.22
Total natural gas distribution throughput (MMcf)	429,354	427,869	393,995	411,134	246,033
Total regulated transmission and storage transportation volumes (MMcf)	595,542	505,493	410,505	373,879	
Total natural gas marketing sales volumes (MMcf)	389,392	370,668	283,962	238,097	222,572
Financial Condition					
Net property, plant and equipment	\$ 4,136,859	\$ 3,836,836	\$ 3,629,156	\$ 3,374,367	\$ 1,722,521
Working capital	78,017	149,217	(1,616)	151,675	283,310
Total assets	6,386,699	5,895,197	5,719,547	5,610,547	2,902,658
Short-term debt, inclusive of current maturities of long-term debt	351,327	154,430	385,602	148,073	5,908
Capitalization:					
Shareholders equity	2,052,492	1,965,754	1,648,098	1,602,422	1,133,459
Long-term debt (excluding current maturities)	2,119,792	2,126,315	2,180,362	2,183,104	861,311
Total capitalization	4,172,284	4,092,069	3,828,460	3,785,526	1,994,770
Capital expenditures	472,273	392,435	425,324	333,183	190,285
Financial Ratios					
Capitalization ratio ⁽⁴⁾	45.4%	46.3%	39.1%	40.7%	56.7%

Return on average shareholders' equity ⁽⁵⁾	8.8%	8.8%	8.9%	9.0%	9.1%
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- (1) Financial results for 2007 and 2006 include a \$6.3 million and a \$22.9 million pre-tax loss for the impairment of certain assets.
- (2) Financial results for 2005 include the results of the Mid-Tex Division and the Atmos Pipeline - Texas Division from October 1, 2004, the date of acquisition.
- (3) Financial results for 2004 include a \$5.9 million pre-tax gain on the sale of our interest in U.S. Propane, L.P. and Heritage Propane Partners, L.P.
- (4) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization and short-term debt, inclusive of current maturities of long-term debt.
- (5) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

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ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, *Risk Factors*. They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words anticipate, believe, estimate, expect, forecast, goal, intend, objective, plan, projection, seek, and similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of recent economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, especially those discussed in Item 1A above, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the

reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful

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accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee quarterly. Actual results may differ from estimates.

Regulation Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our regulated operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation*. This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in their financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized or deferred on the balance sheet because they can be recovered through rates. Discontinuing the application of SFAS 71 could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our natural gas distribution operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

Revenue recognition Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities, which are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of cost, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility company's other costs, (ii) represents a large component of the utility company's cost of service and (iii) is generally outside the control of the gas utility company. There is no gross profit generated through purchased gas adjustments, but they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all natural gas distribution sales to our customers fluctuate with the cost of gas that we purchase, our gross profit is generally not affected by fluctuations in the cost of gas as a result of the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our regulated transmission and storage and pipeline, storage and other segments are recognized in the period in which actual volumes are transported and storage services are provided.

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating

revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes

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in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments.

Allowance for doubtful accounts Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Financial instruments and hedging activities We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses.

We record all of our financial instruments on the balance sheet at fair value as required by SFAS 133, *Accounting for Derivatives and Hedging Activities*, with changes in fair value ultimately recorded in the income statement. We determine fair values primarily through prices actively quoted on national exchanges, which we believe correspond to the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value in those limited circumstances where external sources are not available. Values are adjusted accordingly to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions. Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Fair value estimates also consider the creditworthiness of our counterparties. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and collateral requirements under certain circumstances, including the use of master netting agreements in our natural gas marketing segment.

The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial

instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk in this segment are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a

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component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with SFAS 71. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to the risk of natural gas price changes through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties.

In our natural gas marketing and pipeline, storage and other segments, we have designated the natural gas inventory held by these operating segments as the hedged item in a fair-value hedge. This inventory is marked to market at the end of each month based on the Gas Daily index, with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial instruments designated against our physical inventory (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. The difference in the spot price used to value our physical inventory and the forward price used to value the related financial instruments can result in volatility in our reported income as a component of unrealized margins. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

We have elected to treat fixed-price forward contracts used in our natural gas marketing segment to deliver gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on open financial instruments are recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

We also use storage swaps and futures to capture additional storage arbitrage opportunities in our natural gas marketing segment that arise after the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges in accordance with SFAS 133.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. Currently, we do not have any financial instruments in place to manage interest rate risk. However, in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with

anticipated financings. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement was

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initially recorded as a component of accumulated other comprehensive income (loss) and is recognized as a component of interest expense over the life of the related financing arrangement.

Impairment assessments We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. We currently have no indefinite-lived intangible assets.

We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. We have determined our reporting units to be each of our natural gas distribution divisions and wholly-owned subsidiaries and goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill. The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We annually assess whether the cost of our intangible assets subject to amortization or other long-lived assets is recoverable or that the remaining useful lives may warrant revision. We perform this assessment more frequently when specific events or circumstances have occurred that suggest the recoverability of the cost of the intangible and other long-lived assets is at risk.

When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows from the operating division or subsidiary to which these assets relate. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

Pension and other postretirement plans Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. Effective October 1, 2008, we changed our measurement date to September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or

postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

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We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately \$0.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately \$0.9 million.

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 62 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

During the current year, prices for several world energy commodities rose to historic levels, most significantly seen in unprecedented oil prices. While natural gas prices did not reach historic levels, they were impacted by financial speculators and large hedge fund trading, particularly during the summer months. As a result, our natural gas distribution segment's cost of natural gas per Mcf sold increased 12 percent to \$9.05 for the current fiscal year compared with \$8.09 in the prior fiscal year. Despite these higher prices, we experienced lower price volatility, which reduced our natural gas marketing segment's opportunity to earn arbitrage gains.

Although gas costs do not directly impact our natural gas distribution gross profit margin, higher natural gas prices could cause our natural gas distribution customers and customers served by our other operating segments to conserve, or in the case of industrial customers, switch to less expensive fuel sources. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

We normally access the commercial paper markets to finance our working capital needs and growth. However, recent adverse developments in global financial and credit markets have made it more difficult and more expensive for the Company to access the short-term capital markets, including the commercial paper market, to satisfy our liquidity requirements. Despite these conditions, we believe the amounts available to us under our credit facilities coupled with our operating cash flows will provide the necessary liquidity to fund our working capital needs for fiscal year 2009.

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The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2008, 2007 and 2006.

	For the Fiscal Year Ended September 30		
	2008	2007	2006
	(In thousands, except per share data)		
Operating revenues	\$ 7,221,305	\$ 5,898,431	\$ 6,152,363
Gross profit	1,321,326	1,250,082	1,216,570
Operating expenses	893,431	851,446	833,954
Operating income	427,895	398,636	382,616
Miscellaneous income	2,731	9,184	881
Interest charges	137,922	145,236	146,607
Income before income taxes	292,704	262,584	236,890
Income tax expense	112,373	94,092	89,153
Net income	\$ 180,331	\$ 168,492	\$ 147,737
Earnings per diluted share	\$ 2.00	\$ 1.92	\$ 1.82

Historically, our regulated operations arising from our natural gas distribution and regulated transmission and storage operations contributed 65 to 85 percent of our consolidated net income. Regulated operations contributed 74 percent, 64 percent and 54 percent to our consolidated net income for fiscal years 2008, 2007, and 2006. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended		
	September 30		
	2008	2007	2006
	(In thousands)		
Natural gas distribution segment	\$ 92,648	\$ 73,283	\$ 53,002
Regulated transmission and storage segment	41,425	34,590	26,547
Natural gas marketing segment	29,989	45,769	58,566
Pipeline, storage and other segment	16,269	14,850	9,622
Net income	\$ 180,331	\$ 168,492	\$ 147,737

The following table segregates our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	For the Fiscal Year Ended		
	September 30		
	2008	2007	2006
	(In thousands, except per share data)		

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Regulated operations	\$ 134,073	\$ 107,873	\$ 79,549
Nonregulated operations	46,258	60,619	68,188
Consolidated net income	\$ 180,331	\$ 168,492	\$ 147,737
Diluted EPS from regulated operations	\$ 1.49	\$ 1.23	\$ 0.98
Diluted EPS from nonregulated operations	0.51	0.69	0.84
Consolidated diluted EPS	\$ 2.00	\$ 1.92	\$ 1.82

Year-over-year, net income during fiscal 2008 increased seven percent. Net income from our regulated operations increased 24 percent during fiscal 2008. The increase primarily reflects a net \$53.8 million increase in gross profit resulting from our ratemaking efforts, coupled with higher per-unit transportation margins and an 18 percent increase in consolidated throughput in our Atmos Pipeline Texas Division. These increases were partially offset by a four percent increase in operating expenses. Net income in our nonregulated

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operations experienced a 24 percent decline as less volatile natural gas market conditions significantly reduced our asset optimization margins. However, higher delivered gas margins in our natural gas marketing segment and unrealized margins partially offset this decrease.

The 14 percent year-over-year increase in net income during fiscal 2007 reflects improvements across all business segments. Results from our regulated operations reflect the net favorable impact of various ratemaking rulings in our natural gas distribution segment, including the implementation of WNA in our Mid-Tex and Louisiana Divisions coupled with increased throughput and incremental gross profit margins from our North Side Loop project and other pipeline compression projects completed in fiscal 2006. The decrease in net income from our nonregulated operations primarily reflects the impact of a less volatile natural gas market, which reduced delivered gas margins despite a 31 percent increase in sales volumes. However, our nonregulated operations benefited from higher asset optimization margins, primarily in the pipeline, storage and other segment.

Other key financial and significant events for the fiscal year ended September 30, 2008 include the following:

For the fiscal year ended September 30, 2008, we generated \$370.9 million in operating cash flow compared with \$547.1 million for the fiscal year ended September 30, 2007, primarily reflecting the unfavorable timing of gas cost collections from our customers and cash payments to collateralize our risk management liabilities.

Capital expenditures increased to \$472.3 million during the fiscal year ended September 30, 2008 from \$392.4 million in the prior year. The increase primarily reflects an increase in compliance spending and main replacements in our Mid-Tex Division, spending in the natural gas distribution segment for our new automated meter reading initiative and spending for two nonregulated growth projects.

We repaid \$10.3 million of long-term debt during the fiscal year ended September 30, 2008 compared with a net reduction of long-term debt of \$56.0 million during the prior year. The decreased payments during the current year reflect regularly scheduled maturity payments compared with the prior fiscal year, which reflect the repayment of \$303.2 million of unsecured floating rate senior notes with \$247.2 million of net proceeds received from the issuance of ten year senior notes.

We maintained our capitalization ratio within our targeted range of 50 to 55 percent despite higher short-term borrowings under our existing 5-year credit facility to fund seasonal natural gas purchases at higher prices.

See the following discussion regarding the results of operations for each of our business operating segments.

Fiscal year ended September 30, 2008 compared with fiscal year ended September 30, 2007

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions. The *Ratemaking Activity* section of this Form 10-K describes our current rate strategy and recent ratemaking initiatives in more detail.

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise

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fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	\$ 1,006,066	\$ 952,684	\$ 53,382
Operating expenses	744,901	731,497	13,404
Operating income	261,165	221,187	39,978
Miscellaneous income	9,689	8,945	744
Interest charges	117,933	121,626	(3,693)
Income before income taxes	152,921	108,506	44,415
Income tax expense	60,273	35,223	25,050
Net income	\$ 92,648	\$ 73,283	\$ 19,365
Consolidated natural gas distribution sales volumes MMcf	292,676	297,327	(4,651)
Consolidated natural gas distribution transportation volumes MMcf	136,678	130,542	6,136
Total consolidated natural gas distribution throughput MMcf	429,354	427,869	1,485
Consolidated natural gas distribution average transportation revenue per Mcf	\$ 0.44	\$ 0.45	\$ (0.01)
Consolidated natural gas distribution average cost of gas per Mcf sold	\$ 9.05	\$ 8.09	\$ 0.96

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The following table shows our operating income by natural gas distribution division for the fiscal years ended September 30, 2008 and 2007. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30		
	2008	2007	Change
	(In thousands)		
Mid-Tex	\$ 115,009	\$ 68,574	\$ 46,435
Kentucky/Mid-States	48,731	42,161	6,570
Louisiana	39,090	44,193	(5,103)
West Texas	13,843	21,036	(7,193)
Mississippi	19,970	23,225	(3,255)
Colorado-Kansas	20,615	22,392	(1,777)
Other	3,907	(394)	4,301
Total	\$ 261,165	\$ 221,187	\$ 39,978

The \$53.4 million increase in natural gas distribution gross profit primarily reflects a \$40.7 million net increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division which increased \$29.2 million as a result of its 2006 GRIP filing, the previous and current year Mid-Tex rate cases and the absence of a one time GRIP refund that occurred in the prior year. The current year also reflects \$14.4 million in rate increases in our Kansas, Kentucky, Louisiana, Tennessee and West Texas service areas. In addition, the prior year includes a \$7.5 million accrual for estimated unrecoverable gas costs that did not recur in the current year.

Gross profit also increased approximately \$8.6 million from revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current year compared to the prior year. This increase, partially offset by a \$7.2 million period-over-period increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a \$1.4 million increase in operating income, when compared with the prior year.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased by a net \$13.4 million.

The net increase was primarily reflected in our operation and maintenance expense, excluding the provision for doubtful accounts, which increased \$13.3 million compared with the prior year. The increase principally reflects higher employee and administrative costs in addition to increased natural gas odorization and fuel costs attributable to higher commodity prices. The increase in operation and maintenance expense also reflects the absence in the current-year period of a nonrecurring \$4.3 million deferral of hurricane-related operation and maintenance expenses in the prior year.

The provision for doubtful accounts decreased \$3.2 million to \$16.6 million for the fiscal year ended September 30, 2008, which reflects our continued effective collection efforts, despite a 12 percent rise in our average cost of gas per Mcf sold. As a result of these efforts, our provision for doubtful accounts as a percentage of revenue decreased from 0.61 percent in fiscal 2007 to 0.47 percent in fiscal 2008.

Operating expenses for the prior year also include a \$3.3 million noncash charge associated with the write-off of software costs.

The decrease in operating expenses attributable to the lower provision for doubtful accounts and the absence of the prior year charge were offset by the aforementioned increase in franchise and gross receipt taxes.

Miscellaneous Income

The increase in miscellaneous income primarily reflects the recognition of a \$1.2 million gain on the sale of irrigation assets in our West Texas Division during the fiscal 2008 second quarter.

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Interest charges allocated to the natural gas distribution segment decreased \$3.7 million due to lower average outstanding short-term debt balances in the current year compared with the prior year.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline Texas Division. The Atmos Pipeline Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, as the Atmos Pipeline Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Mid-Tex Division transportation	\$ 86,665	\$ 77,090	\$ 9,575
Third-party transportation	85,256	65,158	20,098
Storage and park and lend services	9,746	9,374	372
Other	14,250	11,607	2,643
Gross profit	195,917	163,229	32,688
Operating expenses	106,172	83,399	22,773
Operating income	89,745	79,830	9,915
Miscellaneous income	1,354	2,105	(751)
Interest charges	27,049	27,917	(868)
Income before income taxes	64,050	54,018	10,032
Income tax expense	22,625	19,428	3,197
Net income	\$ 41,425	\$ 34,590	\$ 6,835

Gross pipeline transportation volumes	MMcf	782,876	699,006	83,870
Consolidated pipeline transportation volumes	MMcf	595,542	505,493	90,049

The \$32.7 million increase in gross profit primarily was attributable to a \$13.1 million increase from rate adjustments resulting from our 2006 and 2007 GRIP filings and an \$8.3 million increase from transportation volumes.

Consolidated throughput increased 18 percent primarily due to increased transportation in the Barnett Shale region of Texas. The improvement in gross profit also reflects increased service fees and per-unit transportation margins due to favorable market conditions which contributed \$8.0 million. New compression

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contracts and transportation capacity enhancements also contributed \$1.5 million. In addition, sales of excess gas increased \$1.3 million compared to the prior year.

Operating expenses increased \$22.8 million primarily due to increased pipeline integrity and maintenance costs.

Natural Gas Marketing Segment

Our natural gas marketing activities are conducted through AEM, which aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

Our asset optimization activities seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time.

AEM continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments to correspond to the revised withdrawal schedule and execute new financial instruments to offset the original financial instruments.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

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Due to the nature of these operations, natural gas prices have a significant impact on our natural gas marketing operations. Within our delivered gas activities, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our natural gas marketing segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the fiscal years ended September 30, 2008 and 2007 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also dependent upon the levels of our net physical position at the end of the reporting period.

	For the Fiscal Year Ended September 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	\$ 73,627	\$ 57,054	\$ 16,573
Asset optimization	(6,135)	28,827	(34,962)
	67,492	85,881	(18,389)
Unrealized margins	25,529	18,430	7,099
Gross profit	93,021	104,311	(11,290)
Operating expenses	36,629	29,271	7,358
Operating income	56,392	75,040	(18,648)
Miscellaneous income	2,022	6,434	(4,412)
Interest charges	9,036	5,767	3,269

Income before income taxes	49,378	75,707	(26,329)
Income tax expense	19,389	29,938	(10,549)
Net income	\$ 29,989	\$ 45,769	\$ (15,780)
Gross natural gas marketing sales volumes MMcf	457,952	423,895	34,057
Consolidated natural gas marketing sales volumes MMcf	389,392	370,668	18,724
Net physical position (Bcf)	8.0	12.3	(4.3)

The \$11.3 million decrease in our natural gas marketing segment's gross profit primarily reflects a \$35.0 million decrease in realized asset optimization margins. As a result of less volatile natural gas market conditions experienced during the current year, AEM regularly deferred storage withdrawals and reset the

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associated financial instruments to increase the potential gross profit it could realize from its asset optimization activities in future periods. As a result, AEM recognized settlement losses without corresponding storage withdrawal gains during the current year. Additionally, AEM experienced increased storage fees charged by third parties during the current year. In the prior year, AEM was able to recognize arbitrage gains as changes in its originally scheduled storage injection and withdrawal plans had a significantly smaller impact than in the current year.

The decrease in realized asset optimization margins was partially offset by a \$16.6 million increase in realized delivered gas margins. The increase reflects both increased sales volumes and increased per-unit margins. Gross sales volumes increased eight percent compared with the prior year. The increase in sales volumes reflects the successful execution of our marketing strategies. Our per-unit margin increased 19 percent, which reflects increased basis gains on certain contracts coupled with improved marketing efforts. Excluding the impact of these basis gains, our per-unit margins increased seven percent in the current year.

Gross profit margin was also favorably impacted by a \$7.1 million increase in unrealized margins attributable to a narrowing of the spreads between current cash prices and forward natural gas prices. The change in unrealized margins also reflects the recognition of previously unrealized margins as a component of realized margins as a result of injecting and withdrawing gas and settling financial instruments as a part of AEM's asset optimization activities.

Operating expenses increased \$7.4 million primarily reflecting a \$2.4 million increase associated with property taxes coupled with a \$5.0 million increase in other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic gross profit, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement is referred to as the potential gross profit.⁽¹⁾ The following table presents AEM's economic gross profit and its potential gross profit at September 30, 2008, 2007 and 2006.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit (In millions)	Associated Net Unrealized Gain (Loss) (In millions)	Potential Gross Profit (In millions)
September 30, 2008	8.0	\$ 48.5	\$ 36.4	\$ 12.1
September 30, 2007	12.3	\$ 40.8	\$ 10.8	\$ 30.0
September 30, 2006	14.5	\$ 60.0	\$ (16.0)	\$ 76.0

⁽¹⁾ Potential gross profit represents the increase in AEM's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include storage and other operating expenses and increased income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic gross profit or the potential gross profit will be fully realized in the future. We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP

measures alone.

As of September 30, 2008, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was \$48.5 million. This amount will be reduced by \$36.4 million of net unrealized gains recorded in the financial statements as of September 30, 2008 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit was \$12.1 million at September 30, 2008.

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The economic gross profit is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential gross profit calculated as of September 30, 2008 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted. Assuming AEM fully executes its plan in place on September 30, 2008, without encountering operational or other issues, we anticipate the majority of the potential gross profit as of September 30, 2008 will be recognized during the first quarter of fiscal 2009 with the remainder recognized over the remaining months in fiscal 2009.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH.

APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM. However, it also provides limited third party transportation services. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Finally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of September 30, 2008, these activities were limited in nature.

APS also engages in limited asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Most of these arrangements are with regulated affiliates of the Company and have been approved by applicable state regulatory commissions. Generally, these arrangements require APS to share with our regulated customers a portion of the profits earned from these arrangements.

AES, through December 31, 2006, provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our natural gas distribution service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our natural gas distribution operations. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Results for this segment are primarily impacted by seasonal weather patterns and, similar to our natural gas marketing segment, volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

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Financial and operational highlights for our pipeline, storage and other segment for the fiscal years ended September 30, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30		
	2008	2007	Change
	(In thousands)		
Storage and transportation services	\$ 13,469	\$ 13,532	\$ (63)
Asset optimization	5,178	11,868	(6,690)
Other	4,961	5,111	(150)
Unrealized margins	4,705	2,097	2,608
Gross profit	28,313	32,608	(4,295)
Operating expenses	8,064	10,373	(2,309)
Operating income	20,249	22,235	(1,986)
Miscellaneous income	8,428	8,173	255
Interest charges	2,322	6,055	(3,733)
Income before income taxes	26,355	24,353	2,002
Income tax expense	10,086	9,503	583
Net income	\$ 16,269	\$ 14,850	\$ 1,419

Pipeline, storage and other gross profit decreased \$4.3 million primarily due to a \$6.7 million decrease in asset optimization margins as a result of a less volatile natural gas market. The decrease in asset optimization margins was partially offset by an increase of \$2.6 million in unrealized margins associated with asset optimization activities.

Operating expenses decreased \$2.3 million primarily due to the absence in the current year of a \$3.0 million noncash charge recorded in the prior year related to the write-off of costs associated with a natural gas gathering project.

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Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2007 and 2006 are presented below.

	For the Fiscal Year Ended September 30		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Gross profit	\$ 952,684	\$ 925,057	\$ 27,627
Operating expenses	731,497	723,163	8,334
Operating income	221,187	201,894	19,293
Miscellaneous income	8,945	9,506	(561)
Interest charges	121,626	126,489	(4,863)
Income before income taxes	108,506	84,911	23,595
Income tax expense	35,223	31,909	3,314
Net income	\$ 73,283	\$ 53,002	\$ 20,281
Consolidated natural gas distribution sales volumes MMcf	297,327	272,033	25,294
Consolidated natural gas distribution transportation volumes MMcf	130,542	121,962	8,580
Total consolidated natural gas distribution throughput MMcf	427,869	393,995	33,874
Consolidated natural gas distribution average transportation revenue per Mcf	\$ 0.45	\$ 0.50	\$ (0.05)
Consolidated natural gas distribution average cost of gas per Mcf sold	\$ 8.09	\$ 10.02	\$ (1.93)

The following table shows our operating income by natural gas distribution division for the fiscal years ended September 30, 2007 and 2006. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	2007		2006	
	Heating Degree Days		Heating Degree Days	
	Operating Income	Percent of Normal⁽¹⁾	Operating Income	Percent of Normal⁽¹⁾
	(In thousands, except degree day information)			
Mid-Tex	\$ 68,574	100%	\$ 71,703	72%
Kentucky/Mid-States	42,161	97%	49,893	98%

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Louisiana	44,193	105%	27,772	78%
West Texas	21,036	99%	2,215	100%
Mississippi	23,225	101%	23,276	102%
Colorado-Kansas	22,392	104%	22,524	99%
Other	(394)		4,511	
Total	\$ 221,187	100%	\$ 201,894	87%

⁽¹⁾ Adjusted for service areas that have weather-normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

The \$27.6 million increase in natural gas distribution gross profit primarily reflects a nine percent increase in throughput and the impact of having WNA coverage for more than 90 percent of our residential

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and commercial customers, partially offset by an accrual for estimated unrecoverable gas costs and lower irrigation margins discussed below. The impact of higher throughput and greater WNA coverage increased gross profit by \$38.6 million. Included in this amount was a \$10.8 million increase associated with the implementation of WNA in our Mid-Tex and Louisiana Divisions beginning with the 2006-2007 winter heating season.

As a result of the Mid-Tex rate case, our gas distribution gross profit increased by \$5.4 million compared to the prior year. This increase was partially offset by a decrease in Mid-Tex transportation revenue as the rate case reduced the transportation rates for certain customer classes. The Mid-Tex rate case also required the refund of \$2.9 million collected under GRIP, which reduced gross profit in the current year.

Favorable regulatory activity in the current year increased gross profit by \$24.4 million, primarily due to an \$11.8 million increase in GRIP-related recoveries and a \$10.2 million increase from our Rate Stabilization Clause (RSC) filings in our Louisiana service areas. These increases were partially offset by an \$11.6 million decrease in gross profit associated with regulatory rulings in our Tennessee, Louisiana and Virginia jurisdictions.

Offsetting these increases in gross profit was a reduction in revenue-related taxes. Due to a significant decline in the cost of gas in the current-year period compared with the prior-year period, franchise and state gross receipts taxes included in gross profit decreased approximately \$2.7 million; however, franchise and state gross receipts tax expense recorded as a component of taxes, other than income decreased \$5.4 million, which resulted in a \$2.7 million increase in operating income when compared with the prior-year period.

Natural gas distribution gross profit also reflects a \$7.5 million accrual for estimated unrecoverable gas costs. The remaining decrease in gross profit primarily is attributable to lower irrigation margins and a reduction in pass-through surcharges used to recover various costs as these costs were fully recovered by the end of fiscal 2006 and during fiscal 2007.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income, and impairment of long-lived assets, increased to \$731.5 million for the fiscal year ended September 30, 2007 from \$723.2 million for the fiscal year ended September 30, 2006.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased \$22.4 million, primarily due to increased employee and other administrative costs. These increases include the personnel and other operating costs associated with the transfer of our gas supply function from our pipeline, storage and other segment to our natural gas distribution segment effective January 1, 2007. Partially offsetting these increases was the deferral of \$4.3 million of operation and maintenance expense in our Louisiana Division resulting from the Louisiana Public Service Commission's ruling to allow recovery of all incremental operation and maintenance expense incurred in fiscal 2005 and 2006 in connection with our Hurricane Katrina recovery efforts.

The provision for doubtful accounts decreased \$0.8 million to \$19.8 million for the fiscal year ended September 30, 2007. The decrease primarily was attributable to reduced collection risk as a result of lower natural gas prices. In the natural gas distribution segment, the average cost of natural gas for the fiscal year ended September 30, 2007 was \$8.09 per Mcf, compared with \$10.02 per Mcf for the year ended September 30, 2006.

Depreciation and amortization expense increased \$12.7 million for the fiscal year ended September 30, 2007 compared with the prior-year period. The increase was primarily attributable to increases in assets placed in service during fiscal 2007. Additionally, the increase was partially attributable to the absence in the current-year period of a \$2.8 million reduction in depreciation expense recorded in the prior-year period arising from the Mississippi Public Service Commission's decision to allow certain deferred costs in our rate base.

Operating expenses for the fiscal year ended September 30, 2007 included a \$3.3 million noncash charge associated with the write-off of costs for software that will no longer be used. Fiscal 2006 results included a \$22.9 million noncash charge to impair the West Texas Division irrigation properties.

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Interest charges allocated to the natural gas distribution segment for the fiscal year ended September 30, 2007 decreased to \$121.6 million from \$126.5 million for the fiscal year ended September 30, 2006. The decrease primarily was attributable to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period.

Regulated Transmission and Storage Segment

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2007 and 2006 are presented below.

	For the Fiscal Year Ended September 30		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Mid-Tex Division transportation	\$ 77,090	\$ 69,925	\$ 7,165
Third-party transportation	65,158	56,813	8,345
Storage and park and lend services	9,374	8,047	1,327
Other	11,607	6,348	5,259
Gross profit	163,229	141,133	22,096
Operating expenses	83,399	77,807	5,592
Operating income	79,830	63,326	16,504
Miscellaneous income (expense)	2,105	(153)	2,258
Interest charges	27,917	22,787	5,130
Income before income taxes	54,018	40,386	13,632
Income tax expense	19,428	13,839	5,589
Net income	\$ 34,590	\$ 26,547	\$ 8,043
Gross pipeline transportation volumes MMcf	699,006	581,272	117,734
Consolidated pipeline transportation volumes MMcf	505,493	410,505	94,988

The \$22.1 million increase in gross profit primarily is attributable to a 23 percent increase in throughput due to colder weather in the current year and incremental volumes from the North Side Loop and other compression projects. These activities increased gross profit by \$16.2 million, of which, \$10.8 million was associated with our North Side Loop and other compression projects completed in fiscal 2006. Increases in gross profit also include a \$3.1 million increase from rate adjustments resulting from our 2005 GRIP filing, a \$2.1 million increase from the sale of excess gas inventory and a \$2.0 million increase from new or renegotiated blending and capacity enhancement contracts.

Operating expenses increased to \$83.4 million for the fiscal year ended September 30, 2007 from \$77.8 million for the fiscal year ended September 30, 2006 due to higher administrative and other operating costs primarily associated with

the North Side Loop and other compression projects that were completed in fiscal 2006.

Interest charges

Interest charges allocated to the pipeline and storage segment for the fiscal year ended September 30, 2007 increased to \$27.9 million from \$22.8 million for the fiscal year ended September 30, 2006. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Table of Contents***Natural Gas Marketing Segment***

Financial and operational highlights for our natural gas marketing segment for the fiscal years ended September 30, 2007 and 2006 are presented below.

	For the Fiscal Year Ended September 30		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	\$ 57,054	\$ 87,236	\$ (30,182)
Asset optimization	28,827	26,225	2,602
	85,881	113,461	(27,580)
Unrealized margins	18,430	17,166	1,264
Gross profit	104,311	130,627	(26,316)
Operating expenses	29,271	28,392	879
Operating income	75,040	102,235	(27,195)
Miscellaneous income	6,434	2,598	3,836
Interest charges	5,767	8,510	(2,743)
Income before income taxes	75,707	96,323	(20,616)
Income tax expense	29,938	37,757	(7,819)
Net income	\$ 45,769	\$ 58,566	\$ (12,797)
Gross natural gas marketing sales volumes MMcf	423,895	336,516	87,379
Consolidated natural gas marketing sales volumes MMcf	370,668	283,962	86,706
Net physical position (Bcf)	12.3	14.5	(2.2)

The \$26.3 million decrease in our natural gas marketing segment's gross profit primarily reflects a \$30.2 million decrease in delivered gas margins. This decrease reflects the impact of a less volatile market, which reduced opportunities to take advantage of pricing differences between hubs, partially offset by a 31 percent increase in sales volumes attributable to successful execution of our marketing strategies and colder weather in the 2007 fiscal year compared with the 2006 fiscal year.

Asset optimization margins increased \$2.6 million compared with the 2006 fiscal year. The increase reflects greater cycled storage volumes as a result of accelerating storage withdrawals scheduled in future periods to capture greater arbitrage gains during the current-year period, partially offset by an increase in storage fees and park and loan fees which reduced the arbitrage spreads available.

Gross profit margin was also favorably impacted by a \$1.3 million increase in unrealized margins attributable to a narrowing of the spreads between current cash prices and forward natural gas prices. The change in unrealized margins also reflects the recognition of previously unrealized margins as a component of realized margins as a result of injecting and withdrawing gas and settling financial instruments as a part of AEM's asset optimization activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$29.3 million for the fiscal year ended September 30, 2007 from \$28.4 million for the fiscal year ended September 30, 2006. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

Miscellaneous income

Miscellaneous income increased to \$6.4 million for the fiscal year ended September 30, 2007 from \$2.6 million for the fiscal year ended September 30, 2006. The increase primarily was attributable to increased investment income earned on overnight investments during the current-year period combined with increased

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interest income earned on our margin account associated with increased margin requirements during the current year.

Interest charges

Interest charges for the fiscal year ended September 30, 2007 decreased to \$5.8 million from \$8.5 million for the fiscal year ended September 30, 2006. The decrease was attributable to lower borrowing requirements during the current-year period.

Pipeline, Storage and Other Segment

Financial and operational highlights for our pipeline, storage and other segment for the fiscal years ended September 30, 2007 and 2006 are presented below.

	For the Fiscal Year Ended September 30		
	2007	2006	Change
	(In thousands)		
Storage and transportation services	\$ 13,532	\$ 8,683	\$ 4,849
Asset optimization	11,868	4,874	6,994
Other	5,111	7,587	(2,476)
Unrealized margins	2,097	3,350	(1,253)
Gross profit	32,608	24,494	8,114
Operating expenses	10,373	9,570	803
Operating income	22,235	14,924	7,311
Miscellaneous income	8,173	6,858	1,315
Interest charges	6,055	6,512	(457)
Income before income taxes	24,353	15,270	9,083
Income tax expense	9,503	5,648	3,855
Net income	\$ 14,850	\$ 9,622	\$ 5,228

Gross profit increased \$8.1 million primarily due to APS' ability to capture more favorable arbitrage spreads from its asset optimization activities, an increase in asset optimization contracts and increased transportation margins.

Operating expenses increased to \$10.4 million for the fiscal year ended September 30, 2007 from \$9.6 million for the fiscal year ended September 30, 2006 primarily due to a \$3.0 million noncash charge associated with the write-off of costs associated with a natural gas gathering project. This increase was partially offset by a decrease in employee and other administrative costs associated with the transfer of gas supply operations from the pipeline, storage and other segment to our natural gas distribution segment effective January 1, 2007.

Miscellaneous income

Miscellaneous income increased to \$8.2 million for the fiscal year ended September 30, 2007 from \$6.9 million for the fiscal year ended September 30, 2006. The increase was primarily attributable to \$2.1 million received from leasing certain mineral interests coupled with an increase in interest income recorded in the pipeline, storage and other segment.

Interest charges

Interest charges allocated to the pipeline, storage and other segment for the fiscal year ended September 30, 2007 decreased to \$6.1 million from \$6.5 million for the fiscal year ended September 30, 2006.

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The decrease was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

LIQUIDITY AND CAPITAL RESOURCES

Our internally generated funds and borrowings under our credit facilities and commercial paper program generally provide the liquidity needed to fund our working capital, capital expenditures and other cash needs. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We normally access the commercial paper markets to finance our working capital needs and growth. However, recent adverse developments in global financial and credit markets, including the recent failure of a major investment bank and the bailout of or merger between several large financial institutions, have made it more difficult and more expensive for the Company to access the short-term capital markets, including the commercial paper market, to satisfy our liquidity requirements.

Consequently, as of September 30, 2008, we had borrowed \$330.5 million directly under our five-year committed credit facility that backstops our commercial paper program to fund most of our working capital. Until recently, our five-year committed credit facility allowed us to borrow up to \$600 million. However, one lender with a 5.55% share of the commitments has ceased funding under the facility. This has effectively limited the amount that we can borrow to approximately \$567 million. The amounts borrowed under the credit facility have been primarily used to purchase large volumes of natural gas in preparation for the upcoming winter heating season. Although our natural gas marketing operations have not been impacted directly in a significant manner yet, continued disruptions in the capital markets could adversely affect the availability of the uncommitted demand credit facility on which such operations substantially relies to conduct its business. A significant reduction in such availability would mean that the Company would need to provide extra liquidity to support the activities of our natural gas marketing business and other nonregulated businesses. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH.

We have historically supplemented our commercial paper program with a short-term \$300 million committed credit facility that must be renewed annually. There were no borrowings under this facility as of September 30, 2008. In October 2008, we replaced this facility upon its termination with a new facility that will allow borrowings up to \$212.5 million and expires in October 2009. Additionally, as more fully described in Note 5, the borrowing costs under the new facility will be significantly higher than under the prior facility.

We believe the amounts available to us under our existing and new credit facilities coupled with operating cash flow will provide the necessary liquidity to fund our working capital needs, capital expenditures and other expenditures for fiscal year 2009.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our services, the demand for our services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the fiscal year ended September 30, 2008, we generated operating cash flow of \$370.9 million compared with \$547.1 million in fiscal 2007 and \$311.4 million in fiscal 2006. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

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Fiscal Year ended September 30, 2008

Operating cash flows were \$176.2 million lower in fiscal 2008 compared to fiscal 2007. The decrease primarily reflects an increase in cash required to collateralize risk management liabilities in our natural gas marketing segment, which reduced operating cash flow by \$95.7 million and the unfavorable timing of gas cost collections in our natural gas distribution segment, which reduced operating cash flow by \$92.6 million.

Fiscal Year ended September 30, 2007

Fiscal 2007 operating cash flows reflect the favorable timing of payments for accounts payable and accrued liabilities, which increased operating cash flow by \$107.6 million. Additionally, improved management of our deferred gas costs balances increased operating cash flow by \$125.2 million. Finally, increased net income and other favorable working capital changes contributed to the increase in operating cash flow. Partially offsetting these increases in operating cash flow was a decrease in customer collections of \$84.8 million due to the decrease in the price of natural gas during the fiscal year.

Fiscal Year ended September 30, 2006

Fiscal 2006 operating cash flows reflect the adverse impact of significantly higher natural gas prices. Year-over-year, unfavorable timing of payments for accounts payable and other accrued liabilities reduced operating cash flow by \$523.0 million. Partially offsetting these outflows were higher customer collections (\$245.1 million) and reduced payments for natural gas inventories (\$102.1 million). Additionally, favorable movements in the market indices used to value our natural gas marketing segment risk management assets and liabilities reduced the amount that we were required to deposit in margin accounts and therefore favorably affected operating cash flow by \$126.3 million.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund acquisitions and growth projects, our ongoing construction program and improvements to information systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return on our investment. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the fiscal year ended September 30, 2008, we incurred \$472.3 million for capital expenditures compared with \$392.4 million for the fiscal year ended September 30, 2007 and \$425.3 million for the fiscal year ended September 30, 2006. The increase in fiscal 2008 primarily reflects an increase in compliance spending and main replacements in our Mid-Tex Division, spending in the natural gas distribution segment for our new automated meter reading initiative and spending for two nonregulated growth projects. The decrease in capital expenditures in fiscal 2007 primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed during the fiscal 2006 third quarter.

Cash flows from financing activities

For the fiscal years ended September 30, 2008 and 2006, our financing activities provided \$98.1 million and \$155.3 million in cash compared with cash of \$159.3 million used for the fiscal year ended September 30, 2007. Our

significant financing activities for the fiscal years ended September 30, 2008, 2007 and 2006 are summarized as follows:

During the fiscal years ended September 30, 2008 and 2006, we increased our borrowings under our short-term facilities by \$200.2 million and \$237.6 million whereas during the fiscal year ended

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September 30, 2007 we repaid a net \$213.2 million under our short-term facilities. Net borrowings under our short-term facilities during fiscal 2008 and 2006 reflect the impact of seasonal natural gas purchases and the effect of higher natural gas prices.

We repaid \$10.3 million of long-term debt during the fiscal year ended September 30, 2008, compared with \$303.2 million during the fiscal year ended September 30, 2007 and \$3.3 million during the fiscal year ended September 30, 2006. The increased payments during fiscal 2007 reflect the repayment of our \$300 million unsecured floating rate senior notes discussed below.

In June 2007, we issued \$250 million of 6.35% Senior Notes due 2017. The effective interest rate of this offering, inclusive of all debt issue costs, was 6.45 percent. After giving effect to the settlement of our \$100 million Treasury lock agreement in June 2007, the effective rate on these senior notes was reduced to 6.26 percent. We used the net proceeds of \$247 million, together with \$53 million of available cash, to repay our \$300 million unsecured floating rate senior notes, which were redeemed on July 15, 2007.

In December 2006, we sold 6.3 million shares of common stock in an offering, including the underwriters exercise of their overallotment option of 0.8 million shares, generating net proceeds of approximately \$192 million. The net proceeds from this issuance were used to reduce our short-term debt.

During the fiscal year ended September 30, 2008, we paid \$117.3 million in cash dividends compared with dividend payments of \$111.7 million and \$102.3 million for the fiscal years ended September 30, 2007 and 2006. The increase in dividends paid over the prior-year reflects the increase in our dividend rate from \$1.28 per share during fiscal 2007 to \$1.30 per share during fiscal 2008, combined with a 1.5 million increase in shares outstanding due to new share issuances under our various equity plans.

During the fiscal year ended September 30, 2008 we issued 1.0 million shares of common stock which generated net proceeds of \$25.5 million. In addition, we granted 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan to directors, officers and other participants in the plan.

The following table shows the number of shares issued for the fiscal years ended September 30, 2008, 2007 and 2006:

	For the Fiscal Year Ended September 30		
	2008	2007	2006
Shares issued:			
Direct stock purchase plan	388,485	325,338	387,833
Retirement savings plan	558,014	422,646	442,635
1998 Long-term incentive plan	538,450	511,584	366,905
Long-term stock plan for Mid-States Division			300
Outside directors stock-for-fee plan	3,197	2,453	2,442
December 2006 equity offering		6,325,000	
Total shares issued	1,488,146	7,587,021	1,200,115

Credit Facilities

As of September 30, 2008, we had three committed credit facilities totaling \$918 million. These facilities included (1) a five-year \$600 million unsecured facility expiring December 2011, (2) a \$300 million unsecured 364-day facility expiring October 2008, and (3) an \$18 million unsecured facility expiring March 2009. However, one lender with a 5.55% share of the commitments under our \$600 million and \$300 million facilities has ceased funding under these facilities. Further, in October 2008, we replaced our \$300 million facility at its termination with a new \$212.5 million unsecured 364-day facility. After giving effect to these changes, the amount available to us under our committed credit facilities was \$797.2 million. As of September 30, 2008, we had no outstanding letters of credit under these facilities.

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AEM has an uncommitted credit facility that can provide up to \$580 million. As of September 30, 2008, the amount available to us under this credit facility, net of outstanding letters of credit, was \$212.1 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months.

Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. However, we believe these credit facilities, combined with our operating cash flows will be sufficient to fund our working capital needs, our fiscal 2009 capital expenditure program and our common stock dividends. These facilities are described in further detail in Note 5 to the consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$900 million in new common stock and/or debt securities available for issuance. As of September 30, 2008, we had approximately \$450 million available for issuance under the registration statement. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately \$200 million of equity securities and \$250 million of senior debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our regulated and nonregulated businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Services, Inc. (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P maintains its positive outlook and Fitch maintains its stable outlook. Moody's recently reaffirmed its stable outlook. None of our ratings are currently under review. However, a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of the recent adverse global financial and credit conditions could trigger a negative change in our

ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean even more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB-, Moody's is Baa3 and Fitch is BBB-. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be

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no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2008. Our debt covenants are described in Note 5 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2008 and 2007:

	September 30			
	2008		2007	
	(In thousands, except percentages)			
Short-term debt	\$ 350,542	7.7%	\$ 150,599	3.5%
Long-term debt	2,120,577	46.9%	2,130,146	50.2%
Shareholders' equity	2,052,492	45.4%	1,965,754	46.3%
Total capitalization, including short-term debt	\$ 4,523,611	100.0%	\$ 4,246,499	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 54.6 percent and 53.7 percent at September 30, 2008 and 2007. The increase in the debt to capitalization ratio primarily reflects an increase in natural gas prices as of September 30, 2008 compared to the prior year. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

Table of Contents**Contractual Obligations and Commercial Commitments**

The following table provides information about contractual obligations and commercial commitments at September 30, 2008.

	Total	Payments Due by Period			More Than 5 Years
		Less Than 1 Year	1-3 Years	3-5 Years	
		(In thousands)			
Contractual Obligations					
Long-term debt ⁽¹⁾	\$ 2,123,612	\$ 785	\$ 760,262	\$ 252,565	\$ 1,110,000
Short-term debt ⁽¹⁾	350,542	350,542			
Interest charges ⁽²⁾	939,048	118,858	196,040	143,226	480,924
Gas purchase commitments ⁽³⁾	550,029	418,949	109,454	18,648	2,978
Capital lease obligations ⁽⁴⁾	1,752	186	372	372	822
Operating leases ⁽⁴⁾	180,317	18,374	33,925	30,924	97,094
Demand fees for contracted storage ⁽⁵⁾	33,411	11,511	14,315	6,698	887
Demand fees for contracted transportation ⁽⁶⁾	104,202	35,522	40,864	14,763	13,053
Financial instrument obligations ⁽⁷⁾	64,283	58,914	5,369		
Postretirement benefit plan contributions ⁽⁸⁾	163,089	12,703	22,083	28,111	100,192
Uncertain tax positions (including interest) ⁽⁹⁾	6,731		6,731		
Total contractual obligations	\$ 4,517,016	\$ 1,026,344	\$ 1,189,415	\$ 495,307	\$ 1,805,950

(1) See Note 5 to the consolidated financial statements.

(2) Interest charges were calculated using the stated rate for each debt issuance.

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2008.

(4) See Note 13 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our natural gas marketing and pipeline, storage and other segments. Contractual demand fees for contracted storage for our natural gas distribution segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(6) Represents third party contractual demand fees for transportation in our natural gas marketing segment.

(7)

Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2008. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.

- (8) Represents expected contributions to our postretirement benefit plans.
- (9) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2008, AEM was committed to purchase 55.8 Bcf within one year, 35.6 Bcf within one to three years and 0.5 Bcf after three years under indexed contracts. AEM was committed to purchase 1.5 Bcf within one year and less than 0.1 Bcf within one to three years under fixed price contracts with prices ranging from \$3.58 to \$13.20 per Mcf.

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With the exception of our Mid-Tex Division, our natural gas distribution segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contract terms as of September 30, 2008 are reflected in the table above.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing and pipeline, storage and other segments, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

We record our financial instruments as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. Substantially all of our financial instruments are valued using external market quotes and indices.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2008 (in thousands):

Fair value of contracts at September 30, 2007	\$ (21,053)
Contracts realized/settled	(27,580)
Fair value of new contracts	(28,308)
Other changes in value	13,264
Fair value of contracts at September 30, 2008	\$ (63,677)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2008, is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at September 30, 2008				
	Maturity in Years				Total Fair Value
	Less Than 1	1-3	4-5	Greater Than 5	
	(In thousands)				
Prices actively quoted	\$ (58,566)	\$ (5,111)	\$	\$	\$ (63,677)
Prices based on models and other valuation methods					

Total Fair Value	\$ (58,566)	\$ (5,111)	\$	\$	\$ (63,677)
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The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the fiscal year ended September 30, 2008 (in thousands):

Fair value of contracts at September 30, 2007	\$ 26,808
Contracts realized/settled	20,363
Fair value of new contracts	
Other changes in value	(30,629)
Fair value of contracts at September 30, 2008	16,542
Netting of cash collateral	56,616
Cash collateral and fair value of contracts at September 30, 2008	\$ 73,158

The fair value of our natural gas marketing segment's financial instruments at September 30, 2008, is presented below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at September 30, 2008					Total Fair Value
	Maturity in Years					
	Less Than 1	1-3	4-5	Greater Than 5		
	(In thousands)					
Prices actively quoted	\$ 12,356	\$ 5,566	\$	\$		\$ 17,922
Prices based on models and other valuation methods	(1,029)	(351)				(1,380)
Total Fair Value	\$ 11,327	\$ 5,215	\$	\$		\$ 16,542

Pension and Postretirement Benefits Obligations***Net Periodic Pension and Postretirement Benefit Costs***

For the fiscal year ended September 30, 2008, our total net periodic pension and other benefits costs was \$47.9 million, compared with \$48.6 million and \$50.0 million for the fiscal years ended September 30, 2007 and 2006. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our total net periodic pension and other benefit costs remained relatively unchanged during the current-year period when compared with the prior-year period as the assumptions we made during our annual pension plan valuation completed June 30, 2007 were consistent with the prior year. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our June 30, 2007 measurement date, the interest rates were consistent with rates at our prior-year measurement date, which resulted in no change to our 6.30 percent discount rate used to determine our fiscal 2008 net periodic and post-retirement cost. In addition, our expected return on our pension plan assets remained constant at 8.25 percent.

The decrease in total net periodic pension and other benefits costs during fiscal 2007 compared with fiscal 2006 primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2006. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2006 measurement date, these interest rates were increasing, which resulted in a 130 basis point increase in our discount rate used to determine our fiscal 2007 net periodic and post-retirement cost to 6.30 percent. This increase had the effect of decreasing the present value of our plan liabilities and associated expenses. This favorable impact was partially offset by the unfavorable impact of reducing the expected return on our pension plan assets by 25 basis points to 8.25 percent, which has the effect of increasing our pension and postretirement benefit costs.

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Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2008 and fiscal 2006, we voluntarily contributed \$2.3 million and \$2.9 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. These contributions achieved a desired level of funding for this plan for plan years 2007 and 2005. During fiscal 2007, we did not contribute to our pension plans.

We contributed \$9.6 million, \$11.8 million and \$10.9 million to our postretirement benefits plans for the fiscal years ended September 30, 2008, 2007 and 2006. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

Outlook for Fiscal 2009

Effective October 1, 2008, the Company adopted the requirement under SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, that the measurement date used to determine our projected benefit and postretirement obligations and net periodic pension and postretirement costs must correspond to a fiscal year end. In accordance with the transition rules, the fiscal 2009 expense will be based upon market conditions as of September 30, 2008.

As of September 30, 2008, interest and corporate bond rates utilized to determine our discount rates, which will impact our fiscal 2009 net periodic pension and postretirement costs, were significantly higher than the interest and corporate bond rates as of June 30, 2007, the measurement date for our fiscal 2008 net periodic cost. Accordingly, we increased our discount rate used to determine our fiscal 2009 pension and benefit costs to 7.57%. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that assets are smoothed for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Accordingly, we expect our fiscal 2009 pension and postretirement medical costs to be materially the same as in fiscal 2008.

Despite the recent decline in the fair value of the plans' assets, we were not required to make a minimum funding contribution to our pension plans during fiscal 2008. However, based upon market conditions subsequent to September 30, 2008, the current funded position of the plans and the new funding requirements under the Pension Protection Act (PPA), we believe it is reasonably possible that we will be required to contribute to the plans in fiscal 2009. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions. With respect to our postretirement medical plans, we anticipate contributing approximately \$3.8 million during fiscal 2009.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the Plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan.

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RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business activities.

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to protect us and our customers against unusually large winter period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 4 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

Natural gas distribution segment

We purchase natural gas for our natural gas distribution operations. Substantially all of the costs of gas purchased for natural gas distribution operations are recovered from our customers through purchased gas adjustment mechanisms. Therefore, our natural gas distribution operations have limited commodity price risk exposure.

Natural gas marketing and pipeline, storage and other segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a \$0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2008 of 0.5 Bcf, a \$0.50 change in the forward NYMEX price would have had a \$0.3 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2008 and assuming our hedges would still qualify as highly effective, a \$0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately \$2.8 million.

Additionally, these changes could cause us to recognize a risk management liability, which would require us to place cash into an escrow account to collateralize this liability position. This, in turn, would reduce the amount of cash we would have on hand to fund our working capital needs.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term

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interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately \$2.1 million during 2008.

We also assess market risk for our fixed rate long-term obligations. We estimate market risk for our long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our long-term obligations would have increased by approximately \$144.2 million.

As of September 30, 2008, we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

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ITEM 8. *Financial Statements and Supplementary Data.*

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<u>Consolidated statements of income for the years ended September 30, 2008, 2007 and 2006</u>	69
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Financial statement schedule for the years ended September 30, 2008, 2007 and 2006	
<u>Schedule II. Valuation and Qualifying Accounts</u>	129

All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and accompanying notes thereto.

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**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON
CONSOLIDATED FINANCIAL STATEMENTS**

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2008 and 2007, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2008. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2008, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atmos Energy Corporation's internal control over financial reporting as of September 30, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 18, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 18, 2008

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ATMOS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	September 30	
	2008	2007
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	\$ 5,650,096	\$ 5,326,621
Construction in progress	80,060	69,449
	5,730,156	5,396,070
Less accumulated depreciation and amortization	1,593,297	1,559,234
Net property, plant and equipment	4,136,859	3,836,836
Current assets		
Cash and cash equivalents	46,717	60,725
Accounts receivable, less allowance for doubtful accounts of \$15,301 in 2008 and \$16,160 in 2007	477,151	380,133
Gas stored underground	576,617	515,128
Other current assets	184,619	111,189
Total current assets	1,285,104	1,067,175
Goodwill and intangible assets	739,086	737,692
Deferred charges and other assets	225,650	253,494
	\$ 6,386,699	\$ 5,895,197
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at \$.005 per share); 200,000,000 shares authorized; issued and outstanding: 2008 90,814,683 shares, 2007 89,326,537 shares	\$ 454	\$ 447
Additional paid-in capital	1,744,384	1,700,378
Accumulated other comprehensive loss	(35,947)	(16,198)
Retained earnings	343,601	281,127
Shareholders' equity	2,052,492	1,965,754
Long-term debt	2,119,792	2,126,315
Total capitalization	4,172,284	4,092,069
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	395,388	355,255
Other current liabilities	460,372	408,273

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Short-term debt	350,542	150,599
Current maturities of long-term debt	785	3,831
Total current liabilities	1,207,087	917,958
Deferred income taxes	441,302	370,569
Regulatory cost of removal obligation	298,645	271,059
Deferred credits and other liabilities	267,381	243,542
	\$ 6,386,699	\$ 5,895,197

See accompanying notes to consolidated financial statements

Table of Contents**ATMOS ENERGY CORPORATION****CONSOLIDATED STATEMENTS OF INCOME**

	Year Ended September 30		
	2008	2007	2006
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	\$ 3,655,130	\$ 3,358,765	\$ 3,650,591
Regulated transmission and storage segment	195,917	163,229	141,133
Natural gas marketing segment	4,287,862	3,151,330	3,156,524
Pipeline, storage and other segment	31,709	33,400	25,574
Intersegment eliminations	(949,313)	(808,293)	(821,459)
	7,221,305	5,898,431	6,152,363
Purchased gas cost			
Natural gas distribution segment	2,649,064	2,406,081	2,725,534
Regulated transmission and storage segment			
Natural gas marketing segment	4,194,841	3,047,019	3,025,897
Pipeline, storage and other segment	3,396	792	1,080
Intersegment eliminations	(947,322)	(805,543)	(816,718)
	5,899,979	4,648,349	4,935,793
Gross profit	1,321,326	1,250,082	1,216,570
Operating expenses			
Operation and maintenance	500,234	463,373	433,418
Depreciation and amortization	200,442	198,863	185,596
Taxes, other than income	192,755	182,866	191,993
Impairment of long-lived assets		6,344	22,947
Total operating expenses	893,431	851,446	833,954
Operating income	427,895	398,636	382,616
Miscellaneous income, net	2,731	9,184	881
Interest charges	137,922	145,236	146,607
Income before income taxes	292,704	262,584	236,890
Income tax expense	112,373	94,092	89,153
Net income	\$ 180,331	\$ 168,492	\$ 147,737
Per share data			
Basic net income per share	\$ 2.02	\$ 1.94	\$ 1.83
Diluted net income per share	\$ 2.00	\$ 1.92	\$ 1.82

Weighted average shares outstanding:

Basic	89,385	86,975	80,731
Diluted	90,272	87,745	81,390

See accompanying notes to consolidated financial statements

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ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock Number of Shares	Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
	(In thousands, except share data)					
Balance, September 30, 2005	80,539,401	\$ 403	\$ 1,426,523	\$ (3,341)	\$ 178,837	\$ 1,602,422
Comprehensive income:						
Net income					147,737	147,737
Unrealized holding gains on investments, net				882		882
Treasury lock agreements, net				3,442		3,442
Cash flow hedges, net				(44,833)		(44,833)
Total comprehensive income						107,228
Cash dividends (\$1.26 per share)					(102,275)	(102,275)
Common stock issued:						
Direct stock purchase plan	387,833	2	10,391			10,393
Retirement savings plan	442,635	2	11,918			11,920
1998 Long-term incentive plan	366,905	2	8,976			8,978
Long-term stock plan for Mid-States Division	300		5			5
Employee stock-based compensation			9,361			9,361
Outside directors stock-for-fee plan	2,442		66			66
Balance, September 30, 2006	81,739,516	409	1,467,240	(43,850)	224,299	1,648,098
Comprehensive income:						
Net income					168,492	168,492
Unrealized holding gains on investments, net				1,241		1,241
Treasury lock agreements, net				6,288		6,288
Cash flow hedges, net				20,123		20,123
Total comprehensive income						196,144
Cash dividends (\$1.28 per share)					(111,664)	(111,664)
Common stock issued:						
Public offering	6,325,000	32	191,881			191,913
Direct stock purchase plan	325,338	2	9,866			9,868
Retirement savings plan	422,646	2	12,929			12,931

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1998 Long-term incentive plan	511,584	2	7,547			7,549
Employee stock-based compensation			10,841			10,841
Outside directors stock-for-fee plan	2,453		74			74
Balance, September 30, 2007	89,326,537	447	1,700,378	(16,198)	281,127	1,965,754
Comprehensive income:						
Net income					180,331	180,331
Unrealized holding losses on investments, net				(1,897)		(1,897)
Treasury lock agreements, net				3,148		3,148
Cash flow hedges, net				(21,000)		(21,000)
Total comprehensive income						160,582
Adoption of FIN 48					(569)	(569)
Cash dividends (\$1.30 per share)					(117,288)	(117,288)
Common stock issued:						
Direct stock purchase plan	388,485	2	10,333			10,335
Retirement savings plan	558,014	3	15,116			15,119
1998 Long-term incentive plan	538,450	2	5,592			5,594
Employee stock-based compensation			12,878			12,878
Outside directors stock-for-fee plan	3,197		87			87
Balance, September 30, 2008	90,814,683	\$ 454	\$ 1,744,384	\$ (35,947)	\$ 343,601	\$ 2,052,492

See accompanying notes to consolidated financial statements

Table of Contents**ATMOS ENERGY CORPORATION****CONSOLIDATED STATEMENTS OF CASH FLOWS**

	Year Ended September 30		
	2008	2007	2006
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	\$ 180,331	\$ 168,492	\$ 147,737
Adjustments to reconcile net income to net cash provided by operating activities:			
Impairment of long-lived assets		6,344	22,947
Depreciation and amortization:			
Charged to depreciation and amortization	200,442	198,863	185,596
Charged to other accounts	147	192	371
Deferred income taxes	97,940	62,121	86,178
Stock-based compensation	14,032	11,934	10,234
Debt financing costs	10,665	10,852	11,117
Other	(5,492)	(1,516)	(2,871)
Changes in assets and liabilities:			
Decrease in cash held on deposit in margin account			9,762
(Increase) decrease in accounts receivable	(97,018)	(6,407)	78,407
Increase in gas stored underground	(61,489)	(53,626)	(10,695)
(Increase) decrease in other current assets	(114,119)	112,588	(59,882)
Decrease in deferred charges and other assets	22,476	23,506	28,614
Increase (decrease) in accounts payable and accrued liabilities	39,902	(8,428)	(116,060)
Increase (decrease) in other current liabilities	60,026	11,661	(70,997)
Increase (decrease) in deferred credits and other liabilities	23,090	10,519	(9,009)
Net cash provided by operating activities	370,933	547,095	311,449
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(472,273)	(392,435)	(425,324)
Other, net	(10,736)	(10,436)	(5,767)
Net cash used in investing activities	(483,009)	(402,871)	(431,091)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	200,174	(213,242)	237,607
Net proceeds from issuance of long-term debt		247,217	
Settlement of Treasury lock agreement		4,750	
Repayment of long-term debt	(10,284)	(303,185)	(3,264)
Cash dividends paid	(117,288)	(111,664)	(102,275)
Issuance of common stock	25,466	24,897	23,273
Net proceeds from equity offering		191,913	
Net cash provided by (used in) financing activities	98,068	(159,314)	155,341
Net increase (decrease) in cash and cash equivalents	(14,008)	(15,090)	35,699

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Cash and cash equivalents at beginning of year	60,725	75,815	40,116
Cash and cash equivalents at end of year	\$ 46,717	\$ 60,725	\$ 75,815

See accompanying notes to consolidated financial statements

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation (Atmos Energy or the Company) and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public-authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri ⁽¹⁾
Atmos Energy Kentucky/Mid-States Division	Georgia ⁽¹⁾ , Illinois ⁽¹⁾ , Iowa ⁽¹⁾ , Kentucky, Missouri ⁽¹⁾ , Tennessee, Virginia ⁽¹⁾
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

⁽¹⁾ Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our natural gas distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate. Our corporate headquarters and shared-services function are located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our regulated transmission and storage business consists of the regulated operations of our Atmos Pipeline Texas Division, a division of the Company. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary to the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and our pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company and based in Houston, Texas.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and

management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments.

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., each of which are wholly-owned by AEH. APS owns or has an interest in underground storage fields in Kentucky and Louisiana.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, APS manages our natural gas gathering operations, which were limited in nature as of September 30, 2008. AES provides limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles in the United States.

2. Summary of Significant Accounting Policies

Principles of consolidation The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated.

Use of estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

Regulation Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Regulated operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

We record regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2008 and 2007 included the following:

	September 30	
	2008	2007
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	\$ 100,563	\$ 59,022
Merger and integration costs, net	7,586	7,996
Deferred gas costs	55,103	14,797
Environmental costs	980	1,303
Rate case costs	12,885	10,989
Deferred franchise fees	651	796
Deferred income taxes, net	343	
Other	8,120	10,719
	\$ 186,231	\$ 105,622
Regulatory liabilities:		
Deferred gas costs	\$ 76,979	\$ 84,043
Regulatory cost of removal obligation	317,273	295,241
Deferred income taxes, net		165
Other	5,639	7,503
	\$ 399,891	\$ 386,952

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2008, 2007 and 2006, we recognized \$0.4 million, \$0.3 million and \$0.5 million in amortization expense related to these costs.

Revenue recognition Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing

method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. There is no gross profit generated through purchased gas adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2008, 2007 and 2006, we included unrealized gains on open contracts of \$25.5 million, \$18.4 million and \$17.2 million as a component of natural gas marketing revenues.

Operating revenues for our regulated transmission and storage and pipeline, storage and other segments are recognized in the period in which actual volumes are transported and storage services are provided.

Cash and cash equivalents We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our natural gas marketing and other nonregulated subsidiaries to conduct their operations. The average cost method is used for all our natural gas distribution divisions, except for certain jurisdictions in the Kentucky/Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. The average gas cost method is also used for our regulated transmission and storage segment. Our natural gas marketing and pipeline, storage and other segments utilize the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of \$2.9 million, \$3.0 million and \$3.6 million was capitalized in 2008,

2007 and 2006.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.7 percent, 3.9 percent and 3.9 percent for the fiscal years ended September 30, 2008, 2007 and 2006.

Nonregulated property, plant and equipment Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 35 years.

Asset retirement obligations SFAS 143, *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations* require that we record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2008 and 2007, we had recorded asset retirement obligations of \$5.9 million and \$9.0 million. Additionally, we recorded \$1.3 million and \$2.9 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

We believe we have a legal obligation to retire our storage wells. However, we have not recognized an asset retirement obligation associated with our storage wells because there is not sufficient industry history to reasonably estimate the fair value of this obligation.

Impairment of long-lived assets We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

During fiscal 2007, we recorded a \$6.3 million charge associated with the write-off of approximately \$3.0 million of costs related to a nonregulated natural gas gathering project and approximately \$3.3 million of obsolete software costs. During the fourth quarter of fiscal 2006, we determined that, as a result of declining irrigation sales primarily associated with our agricultural customers' shift from gas-powered pumps to electric pumps, the West Texas Division's irrigation assets would not be able to generate sufficient future cash flows from operations to recover the net investment in these assets. Therefore, we recorded a \$22.9 million charge to impairment to write off the entire net book value.

Goodwill and intangible assets We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible assets are amortized over their useful lives of 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. No impairment has been recognized.

Marketable securities As of September 30, 2008 and 2007, all of our marketable securities were classified as available-for-sale based upon the criteria of SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*. In accordance with that standard, these securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value.

Financial instruments and hedging activities We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored for our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. The objectives and strategies for the use of financial instruments are discussed in Note 4.

We record all of our financial instruments on the balance sheet at fair value as required by SFAS 133, *Accounting for Derivatives and Hedging Activities*, with changes in fair value ultimately recorded in the income statement. These financial instruments are reported as risk management assets and liabilities and are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying financial instrument.

The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, the costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with SFAS 71. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

In our natural gas marketing and pipeline, storage and other segments, we have designated the natural gas inventory held by these operating segments as the hedged item in a fair-value hedge. This inventory is marked to market at the end of each month based on the Gas Daily index, with changes in fair value recognized as unrealized gains or losses in

revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) result in unrealized margins until the underlying physical gas is withdrawn and

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

In our natural gas marketing segment, we have elected to treat fixed-price forward contracts to deliver natural gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on these open financial instruments are recorded as a component of accumulated other comprehensive income, and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity are referred to as timing ineffectiveness.

In our natural gas marketing segment, the following summarizes the gains and losses recognized in the income statement for the fiscal years ended September 30, 2008, 2007 and 2006.

	For the Fiscal Year Ended September 30		
	2008	2007	2006
	(In thousands)		
Basis ineffectiveness:			
Fair-value basis ineffectiveness	\$ (2,841)	\$ 783	\$ 15,476
Cash flow basis ineffectiveness	3,720	2,330	7,392
Total basis ineffectiveness	879	3,113	22,868
Timing ineffectiveness:			
Fair-value timing ineffectiveness	39,695	89,207	(17,832)
Total hedge ineffectiveness	\$ 40,574	\$ 92,320	\$ 5,036

In our pipeline, storage and other segment, actual hedge ineffectiveness arising from the timing of settlement of physical contracts and the settlement of the financial instruments resulted in a gain of approximately \$5.4 million and \$8.4 million for the fiscal years ended September 30, 2008 and 2007 and a loss of approximately \$7.0 million for the

fiscal year ended September 30, 2006.

Prices actively quoted on national exchanges are used to determine the fair value of most of our financial instruments. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted accordingly to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these financial instruments represent the best information

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

Fair-value estimates also consider the creditworthiness of our counterparties. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. A continued tightening of the credit market could cause more of our counterparties to fail to perform than expected and reserved. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

In our natural gas marketing segment, we also utilize master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place.

In April 2007, the Financial Accounting Standards Board (FASB) issued FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*. This FSP requires that, to the extent we utilize master netting agreements to offset gains and losses arising from financial instruments, we must include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted. This FSP is applicable to the Company effective October 1, 2008 and early adoption is permitted. We have elected to adopt this FSP as of September 30, 2008. As a result of adopting this FSP, the Company netted \$56.6 million of cash held in margin accounts into its current risk management assets and liabilities as of September 30, 2008. The adoption of this interpretation also required a reclassification as of September 30, 2007 of a \$1.7 million obligation to return cash from other current liabilities to risk management assets. This requirement to net this cash position against risk management assets and liabilities did not have a material impact on our financial position or working capital.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. Currently, we do not have any financial instruments in place to manage interest rate risk. However, in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

Pension and other postretirement plans Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other

postretirement plan costs and liabilities annually based upon a June 30 measurement date. To comply with the new measurement date requirements of SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, effective October 1, 2008, we changed our measurement date from June 30 to our fiscal year end, September 30. This change is more fully discussed in Note 8. The assumed discount rate

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our annual postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon the annual review of our participant census information as of the measurement date.

Income taxes Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

Stock-based compensation plans We maintain the 1998 Long-Term Incentive Plan that provides for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to officers, division presidents and other key employees. Non-employee directors are also eligible to receive stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

Accumulated other comprehensive loss Accumulated other comprehensive loss, net of tax, as of September 30, 2008 and 2007 consisted of the following unrealized gains (losses):

September 30

	2008	2007
	(In thousands)	
Unrealized holding gains on investments	\$ 910	\$ 2,807
Treasury lock agreements	(11,104)	(14,252)
Cash flow hedges	(25,753)	(4,753)
	\$ (35,947)	\$ (16,198)

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recent accounting pronouncements In March 2008, the FASB issued FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133*. SFAS 161 expands the disclosure requirements for derivative instruments and for hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. Although the provisions of this standard will be effective for us beginning January 1, 2009, we adopted this standard effective October 1, 2008. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued FASB Statement No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosure on fair value measurements required under other accounting pronouncements but does not change existing guidance as to whether or not an instrument is carried at fair value. We will be required to apply the provisions of SFAS 157 beginning October 1, 2008. We believe this standard will not materially impact our financial position, results of operations or cash flows. However, it will significantly expand our disclosure concerning the fair value measurements reflected in our financial statements.

In February 2007, the FASB issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115*. This new standard permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The provisions of this standard will be effective October 1, 2008. We do not anticipate this standard will materially impact our financial position, results of operations or cash flows.

In December 2007, the FASB issued FASB Statement No. 141 (revised 2007), *Business Combinations*. SFAS 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS 141(R) significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under SFAS 141(R), changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. The provisions of this standard will apply to any acquisitions we may complete after October 1, 2009.

In December 2007, the FASB issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statement, an amendment of ARB No. 51*. SFAS 160 changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. The provisions of the standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****3. Goodwill and Intangible Assets**

Goodwill and intangible assets were comprised of the following as of September 30, 2008 and 2007.

	September 30	
	2008	2007
	(In thousands)	
Goodwill	\$ 736,998	\$ 734,976
Intangible assets	2,088	2,716
Total	\$ 739,086	\$ 737,692

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2008:

	Natural Gas Distribution Segment	Regulated Transmission and Storage Segment	Natural Gas Marketing Segment	Pipeline, Storage and Other Segment	Total
	(In thousands)				
Balance as of September 30, 2007	\$ 567,775	\$ 132,490	\$ 24,282	\$ 10,429	\$ 734,976
Deferred tax adjustments on prior acquisitions ⁽¹⁾	2,145	(123)			2,022
Balance as of September 30, 2008	\$ 569,920	\$ 132,367	\$ 24,282	\$ 10,429	\$ 736,998

⁽¹⁾ During the preparation of the fiscal 2008 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of \$2.0 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2008 and 2007, we had no intangible assets with indefinite lives.

	September 30, 2008		September 30, 2007	
	Useful	Gross	Gross	

	Life (Years)	Carrying Amount	Accumulated Amortization	Net	Carrying Amount	Accumulated Amortization	Net
				(In thousands)			
Customer contracts	10	\$ 6,926	\$ (4,838)	\$ 2,088	\$ 6,926	\$ (4,210)	\$ 2,716

The following table presents actual amortization expense recognized during 2008 and an estimate of future amortization expense based upon our intangible assets at September 30, 2008.

Amortization expense (in thousands):

Actual for the fiscal year ending September 30, 2008	\$ 628
Estimated for the fiscal year ending:	
September 30, 2009	627
September 30, 2010	627
September 30, 2011	627
September 30, 2012	43
September 30, 2013	43

4. Financial Instruments and Hedging Activities

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments.

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However, our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment.

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2008 and 2007:

	Natural Gas Distribution	Natural Gas Marketing (In thousands)	Total
September 30, 2008:			
Assets from risk management activities, current ⁽¹⁾	\$	\$ 68,291	\$ 68,291
Assets from risk management activities, noncurrent		5,473	5,473
Liabilities from risk management activities, current ⁽¹⁾	(58,566)	(348)	(58,914)
Liabilities from risk management activities, noncurrent	(5,111)	(258)	(5,369)
Net assets (liabilities)	\$ (63,677)	\$ 73,158	\$ 9,481
September 30, 2007:			
Assets from risk management activities, current ⁽²⁾	\$	\$ 20,129	\$ 20,129
Assets from risk management activities, noncurrent		5,535	5,535
Liabilities from risk management activities, current	(21,053)	(286)	(21,339)
Liabilities from risk management activities, noncurrent		(290)	(290)
Net assets (liabilities)	\$ (21,053)	\$ 25,088	\$ 4,035

⁽¹⁾ Includes \$56.6 million of cash held on deposit in margin accounts to collateralize certain financial instruments. Of this amount, \$29.8 million was used to offset current risk management liabilities under master netting agreements and the remaining \$26.8 million is classified as current risk management assets.

⁽²⁾ Includes a \$1.7 million obligation to return cash collateral, which was used to offset current risk management assets under master netting agreements.

Regulated Commodity Risk Management Activities

Although our purchased gas adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our natural gas distribution customers are exposed to the effect of volatile natural gas prices.

We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. If the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2007-2008 heating season, we hedged approximately 45 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately \$7.61 per Mcf.

We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Future contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers, and we use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges pursuant to FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. Our risk management committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions

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as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2008, AEH had a net open position (including existing storage) of 0.5 Bcf.

Interest Rate Risk Management Activities

Currently, we are not managing interest rate risk with financial instruments. However, in prior years, we periodically managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

In fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the-then anticipated issuance of \$875 million of long-term debt issued in October 2004 in connection with the permanent financing for our TXU Gas acquisition. These Treasury lock agreements were settled in October 2004 with a net \$43.8 million payment to the counterparties.

In March 2007, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with \$100 million of our \$250 million 6.35% Senior Notes issued in June 2007. This Treasury lock agreement was settled in June 2007, which resulted in the receipt of \$2.9 million from the counterparties.

The gains and losses realized upon settlement were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement.

Cash Flow Hedging Information

As of September 30, 2008 and 2007, deferred amounts associated with our natural gas marketing forward commodity contracts and our Treasury lock agreements were included in other comprehensive income (loss). The following table presents the amount of other comprehensive income (loss), net of taxes, associated with these financial instruments during the fiscal years ended September 30, 2008 and 2007.

	Fiscal Year Ended September 30	
	2008	2007
	(In thousands)	
<i>Increase (decrease) in fair value:</i>		
Treasury lock agreements	\$	\$ 2,945
Forward commodity contracts	(13,213)	(10,861)
<i>Recognition of (gains) losses in earnings due to settlements:</i>		
Treasury lock agreements	3,148	3,343
Forward commodity contracts	(7,787)	30,984

Total other comprehensive income (loss) from hedging, net of tax ⁽¹⁾	\$ (17,852)	\$ 26,411
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⁽¹⁾ Utilizing an income tax rate of approximately 38 percent comprised of the effective rates in each taxing jurisdiction.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred amounts associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2008:

	Treasury Lock Agreements	Forward Commodity Contracts (In thousands)	Total
2009	\$ (3,147)	\$ (24,878)	\$ (28,025)
2010	(1,828)	(885)	(2,713)
2011	(1,709)	58	(1,651)
2012	(1,709)	(58)	(1,767)
2013	(1,709)	10	(1,699)
Thereafter	(1,002)		(1,002)
Total	\$ (11,104)	\$ (25,753)	\$ (36,857)

5. Debt***Long-term debt***

Long-term debt at September 30, 2008 and 2007 consisted of the following:

	2008 (In thousands)	2007
Unsecured 4.00% Senior Notes, due October 2009	\$ 400,000	\$ 400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds Series P, 10.43% due 2013		7,500
Rental property, propane and other term notes due in installments through 2013	1,309	3,890

Total long-term debt	2,123,612	2,133,693
Less:		
Original issue discount on unsecured senior notes and debentures	(3,035)	(3,547)
Current maturities	(785)	(3,831)
	\$ 2,119,792	\$ 2,126,315

Short-term debt

At September 30, 2008, we had \$350.5 million of short-term debt outstanding comprised of \$330.5 million outstanding under our bank credit facilities and \$20.0 million outstanding under our commercial paper

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

program. At September 30, 2007 we had \$150.6 million outstanding under our commercial paper program. There were no amounts outstanding under our bank credit facilities at September 30, 2007. As of September 30, 2008, our commercial paper had maturities of less than three months, with an interest rate of 3.35 percent.

Shelf registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$900 million in new common stock and/or debt securities available for issuance. As of September 30, 2008, we had approximately \$450 million of availability remaining under the registration statement. Due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately \$200 million of equity securities and \$250 million of senior debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until we received an investment grade rating from all of the three credit rating agencies.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the bank. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of September 30, 2008, we had three committed revolving credit facilities totaling \$918 million. The first facility is a five-year unsecured facility, expiring December 2011, that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At the time this credit facility was established, the limit on borrowings under the facility was \$600 million. However, in September 2008, the limit on borrowings was effectively reduced to approximately \$567 million after one lender with a 5.55% share of the commitments ceased funding under the facility. At September 30, 2008, there was \$216.2 million available under the credit facility.

The second facility is a \$300 million unsecured 364-day facility expiring October 2008, that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. In September 2008, the limit on borrowings was reduced to approximately \$283 million after one lender with a 5.55% share of the commitments ceased funding under the facility. At September 30, 2008, there were no borrowings under this facility. In October 2008, this facility was replaced upon its termination by a \$212.5 million unsecured 364-day facility that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 1.25 percent to 2.50 percent, based on the Company's credit ratings.

The third facility is an \$18 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility expired on March 31, 2008 and was renewed effective April 1, 2008 for one year with no material changes to the terms and pricing. At September 30, 2008, there were no borrowings under this facility.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2008, our total-debt-to-total-capitalization ratio, as defined, was 57 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt to-total capitalization ratio.

Uncommitted credit facilities

AEM has a \$580 million uncommitted demand working capital credit facility. On March 31, 2008, AEM and the participating banks amended the facility, primarily to extend it to March 31, 2009. In addition, the amendment removed the financial covenant relating to the amount of cumulative losses that could be incurred by AEM and its subsidiaries over a specific period of time and included provisions permitting the participating banks, or their affiliates, to participate in physical commodity transactions with AEM.

Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR for the applicable interest period plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility not to exceed a maximum ratio of total liabilities to tangible net worth of 5 to 1. At September 30, 2008, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.58 to 1. Additionally, AEM must maintain minimum levels of net working capital ranging from \$20 million to \$120 million and a minimum tangible net worth ranging from \$21 million to \$121 million. As defined in the financial covenants, at September 30, 2008, AEM's net working capital was \$218.8 million and its tangible net worth was \$232.5 million.

At September 30, 2008, there were no borrowings outstanding under this credit facility. However, at September 30, 2008, AEM letters of credit totaling \$87.9 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was \$212.1 million at September 30, 2008. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company has a \$200 million intercompany uncommitted revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.20 percent or (ii) the marginal borrowing rate available to

the Company on any such date under its commercial paper program. Applicable state regulatory commissions have approved this facility through December 31, 2008. The Company has applied for renewal of these approvals through December 31, 2009. At September 30, 2008, there were no borrowings outstanding under this facility.

AEH has a \$200 million intercompany uncommitted demand credit facility with the Company, which bears interest at the rate of AEM's \$580 million uncommitted demand working capital credit facility plus

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0.75 percent. Applicable state regulatory commissions have approved this facility through December 31, 2008. The Company has applied for renewal of these approvals through December 31, 2009. At September 30, 2008, there was \$35.1 million outstanding under this facility.

In addition, to supplement its \$580 million credit facility, AEM has a \$200 million intercompany uncommitted demand credit facility with AEH, which bears interest at the rate of AEM's \$580 million uncommitted demand working capital credit facility plus 0.75 percent. Any outstanding amounts under this facility are subordinated to AEM's \$580 million uncommitted demand credit facility. At September 30, 2008, there was \$6.5 million outstanding under this facility.

Debt Covenants

In addition to the covenants described above, our Series P First Mortgage Bonds contained provisions that allowed us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provided for certain cash flow requirements and restrictions on the incurrence of additional indebtedness, sales of assets and payments of dividends. In May 2008, we redeemed our Series P First Mortgage Bonds which were scheduled to mature in November 2013. Since the bonds have been redeemed and the related indenture has been discharged, the debt covenants described above no longer apply.

We were in compliance with all of our debt covenants as of September 30, 2008. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of \$15 million to in excess of \$100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least \$250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if the Company were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other triggering events.

Based on the borrowing rates currently available to us for debt with similar terms and remaining average maturities, the fair value of long-term debt at September 30, 2008 and 2007 is estimated, using discounted cash flow analysis, to be \$1,955.5 million and \$2,026.6 million.

Maturities of long-term debt at September 30, 2008 were as follows (in thousands):

2009	\$	785
2010		400,131
2011		360,131
2012		2,434

2013	250,131
Thereafter	1,110,000
	\$ 2,123,612

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Shareholders Equity

Stock Issuances

During the fiscal years ended September 30, 2008, 2007 and 2006 we issued 1,488,146, 7,587,021 and 1,200,115 shares of common stock.

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at \$31.50 per share and generated net proceeds of approximately \$192 million. We used the net proceeds from this offering to reduce short-term debt.

Shareholder Rights Plan

In November 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998, the description and terms of which were set forth in a rights agreement between us and the rights agent dated May 10, 1998. From that time until the expiration of the rights agreement on May 10, 2008, when all rights terminated, each share of common stock we issued included a right that entitled the holder to purchase from us a one-tenth share of our common stock at a purchase price of \$8.00 per share, subject to adjustment.

7. Stock and Other Compensation Plans

Stock-Based Compensation Plans

Total stock-based compensation expense was \$14.0 million, \$11.9 million and \$10.2 million for the fiscal years ended September 30, 2008, 2007 and 2006, primarily related to restricted stock costs.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock. We are authorized to grant awards for up to a maximum of 6.5 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2008, non-qualified stock options, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units had been issued under this plan, and 2,122,776 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive

Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period. The following summarizes

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2008, 2007 and 2006:

	2008		2007		2006	
	Number of	Weighted Average Grant- Date Fair Value	Number of Restricted Shares	Weighted Average Grant- Date Fair Value	Number of Restricted Shares	Weighted Average Grant- Date Fair Value
Nonvested at beginning of year	948,717	\$ 28.95	746,776	\$ 26.49	592,490	\$ 25.32
Granted	547,845	27.90	485,260	30.85	440,016	26.80
Vested	(380,895)	27.17	(271,075)	26.12	(265,546)	24.42
Forfeited	(18,897)	29.32	(12,244)	28.51	(20,184)	26.95
Nonvested at end of year	1,096,770	\$ 29.04	948,717	\$ 28.95	746,776	\$ 26.49

As of September 30, 2008, there was \$16.3 million of total unrecognized compensation cost related to nonvested restricted shares granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2008, 2007 and 2006 was \$10.3 million, \$7.1 million and \$6.5 million.

Stock Option Plan

We used the Black-Scholes pricing model to estimate the fair value of each option granted with the following weighted average assumptions for fiscal year 2006. No stock options were granted in fiscal years 2007 and 2008.

	Fiscal Year Ended September 30, 2006
Valuation Assumptions	
Expected Life (years) ⁽¹⁾	7
Interest rate ⁽²⁾	4.6%
Volatility ⁽³⁾	20.3%
Dividend yield	4.8%

⁽¹⁾ The expected life of stock options is estimated based on historical experience.

- (2) The interest rate is based on the U.S. Treasury constant maturity interest rate whose term is consistent with the expected life of the stock options.
- (3) The volatility is estimated based on historical and current stock data for the Company.

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A summary of activity for grants of stock options under the LTIP follows:

	2008		2007		2006	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	920,841	\$ 22.54	1,017,152	\$ 22.57	964,704	\$ 22.20
Granted					93,196	26.19
Exercised	(7,000)	21.90	(92,071)	22.84	(40,582)	22.21
Forfeited			(4,240)	23.11	(166)	21.23
Outstanding at end of year ⁽¹⁾	913,841	\$ 22.54	920,841	\$ 22.54	1,017,152	\$ 22.57
Exercisable at end of year ⁽²⁾	911,492	\$ 22.53	908,332	\$ 22.49	991,778	\$ 22.48

(1) The weighted-average remaining contractual life for outstanding options was 3.4 years, 4.4 years, and 5.4 years for fiscal years 2008, 2007 and 2006. The aggregate intrinsic value of outstanding options was \$3.3 million, \$3.3 million and \$3.7 million for fiscal years 2008, 2007 and 2006.

(2) The weighted-average remaining contractual life for exercisable options was 3.4 years, 4.3 years, and 5.3 years for fiscal years 2008, 2007 and 2006. The aggregate intrinsic value of exercisable options was \$3.3 million, \$3.3 million and \$3.6 million for fiscal years 2008, 2007 and 2006.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2008, is reflected in the following tables:

	Options Outstanding			Options Exercisable	
	Number of Options	Weighted Average Remaining Contractual Life (In Years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Range of Exercise Prices					
\$15.65 to \$20.24	61,833	1.4	\$ 15.66	61,833	\$ 15.66

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\$20.25 to \$22.99	493,525	3.8	\$ 21.86	493,525	\$ 21.86
\$23.00 to \$26.19	358,483	3.2	\$ 24.66	356,134	\$ 24.65
\$15.65 to \$26.19	913,841	3.4	\$ 22.54	911,492	\$ 22.53

Fiscal Year Ended September 30
2008 2007 2006
(In thousands, except per share data)

Grant date weighted average fair value per share			\$ 3.74
Net cash proceeds from stock option exercises	\$ 153	\$ 2,103	\$ 901
Income tax benefit from stock option exercises	\$ 12	\$ 296	\$ 78
Total intrinsic value of options exercised	\$ 26	\$ 347	\$ 143

As of September 30, 2008, there was less than \$0.1 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a weighted-average period of 0.1 years.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan, open to all investors, which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. The minimum initial investment required to join the plan is \$1,250. Direct Stock Purchase Plan participants may purchase additional shares of our common stock as often as weekly with voluntary cash payments of at least \$25, up to an annual maximum of \$100,000.

Outside Directors Stock-For-Fee Plan

In November 1994, the Board adopted the Outside Directors Stock-for-Fee Plan which was approved by our shareholders in February 1995 and was amended and restated in November 1997. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by our shareholders in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company in May 1990 and replaced the pension payable under our Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos Energy with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

Other Discretionary Compensation Plans

We adopted the Variable Pay Plan in fiscal 1999 for our regulated segments employees to give each employee an opportunity to share in our financial success based on the achievement of key performance measures considered critical to achieving business objectives for a given year and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded. During the last several fiscal years, we have used earnings per share as our sole performance measure.

We adopted our Annual Incentive Plan in October 2001 to give the employees in our nonregulated segments an opportunity to share in the success of the nonregulated operations. The plan is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

8. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Effective September 30, 2007, we adopted the provisions of SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. The new standard made a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity.

Additionally, this standard required that our measurement date correspond to the fiscal year end balance sheet date by as late as fiscal 2009 for the Company. Effective October 1, 2008, the Company adopted the measurement date requirement of SFAS 158 using the remeasurement approach. Under this approach, the Company remeasured its projected benefit obligation, fair value of plan assets and its fiscal 2009 net periodic cost. In accordance with the transition rules of SFAS 158, the impact of changing the measurement date will decrease retained earnings by \$7.8 million, net of tax, decrease the unrecognized actuarial loss by \$9.0 million and increase our postretirement liabilities by \$3.5 million as of October 1, 2008.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. Therefore, the decrease in the unrecognized actuarial loss that would have been recorded as a component of accumulated other comprehensive loss, net of tax, will be recorded as a reduction to a regulatory asset as a component of deferred charges and other assets in fiscal 2009. The change in the measurement date will not materially impact the level of net periodic pension cost we will record in fiscal 2009.

The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
	(In thousands)			
September 30, 2008				
Unrecognized transition obligation	\$	\$	\$ 8,131	\$ 8,131
Unrecognized prior service cost	(2,984)	452		(2,532)
Unrecognized actuarial loss	64,815	17,308	12,841	94,964
	\$ 61,831	\$ 17,760	\$ 20,972	\$ 100,563
September 30, 2007				
Unrecognized transition obligation	\$	\$	\$ 9,642	\$ 9,642
Unrecognized prior service cost	(4,142)	664		(3,478)
Unrecognized actuarial loss	31,022	22,164	(328)	52,858
	\$ 26,880	\$ 22,828	\$ 9,314	\$ 59,022

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2008, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan, that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan will credit this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applies through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants fully vest in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity.

The Union Plan is a defined benefit plan that covers substantially all full-time union employees in our Mississippi Division. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2008 and fiscal 2006, we voluntarily contributed \$2.3 million and \$2.9 million to the Union Plan. These contributions achieved a desired level of funding for this plan for the plan years 2007 and 2005. During fiscal 2007, we did not make any contributions to the Plans. However, based upon market conditions subsequent to September 30, 2008, the current funded position of the plans and the new funding requirements under the PPA, we believe it is reasonably possible that we will be required to contribute to the Plans in fiscal 2009. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions.

We manage the Master Trust's assets with the objective of achieving a rate of return net of inflation of approximately four percent per year. We make investment decisions and evaluate performance on a medium term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long-term asset investment policy adopted by the Board of Directors.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds, other investment assets and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors in an effort to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents asset allocation information for the Master Trust as of September 30, 2008 and 2007.

Security Class	Targeted Allocation Range	Actual Allocation September 30	
		2008	2007
Domestic equities	35%-55%	42.0%	44.9%
International equities	10%-20%	11.0%	15.2%
Fixed income	10%-30%	24.2%	20.1%
Company stock	0%-10%	10.2%	8.5%
Other assets	5%-15%	10.2%	9.6%
Cash and equivalents	0%-10%	2.4%	1.7%

At September 30, 2008 and 2007, the Plan held 1,169,700 shares of our common stock, which represented 10.2 percent and 8.5 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately \$1.5 million during fiscal 2008 and 2007.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a June 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of June 30, 2008 and 2007 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of June 30, 2007, 2006 and 2005. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2008	2007	2008	2007	2006
Discount rate	6.68%	6.30%	6.30%	6.30%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%	8.50%

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2008 and 2007 based upon a June 30, 2008 and 2007 measurement date.

	2008	2007
	(In thousands)	
Accumulated benefit obligation	\$ 329,023	\$ 325,574
Change in projected benefit obligation:		
Benefit obligation at beginning of year	\$ 335,581	\$ 326,464
Service cost	13,329	13,090
Interest cost	21,129	20,396
Actuarial loss (gain)	(6,939)	4,034
Benefits paid	(25,721)	(28,403)
Plan amendments	261	
Benefit obligation at end of year	337,640	335,581
Change in plan assets:		
Fair value of plan assets at beginning of year	389,073	362,714
Actual return on plan assets	(21,972)	54,762
Employer contributions ⁽¹⁾		
Benefits paid	(25,721)	(28,403)
Fair value of plan assets at end of year	341,380	389,073
Reconciliation:		
Funded status	3,740	53,492
Unrecognized prior service cost		
Unrecognized net loss		
Net amount recognized	\$ 3,740	\$ 53,492

⁽¹⁾ During the fourth quarter of fiscal 2008, we voluntarily contributed \$2.3 million to the Union Plan. However, this contribution is not reflected in this table because it occurred after the June 30, 2008 measurement date.

Net periodic pension cost for the Plans for fiscal 2008, 2007 and 2006 is recorded as operating expense and included the following components:

Fiscal Year Ended September 30		
2008	2007	2006

(In thousands)

Components of net periodic pension cost:

Service cost	\$ 13,329	\$ 13,090	\$ 13,465
Interest cost	21,129	20,396	17,932
Expected return on assets	(25,242)	(24,357)	(25,598)
Amortization of prior service cost	(897)	(838)	(959)
Recognized actuarial loss	6,482	8,253	10,469
Net periodic pension cost	\$ 14,801	\$ 16,544	\$ 15,309

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)***Supplemental Executive Benefits Plans*

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to our officers, division presidents and certain other employees of the Company who were employed on or before August 12, 1998. In addition, in August 1998, we adopted the Supplemental Executive Retirement Plan (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of June 30, 2008 and 2007 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of June 30, 2007, 2006 and 2005. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2008	2007	2008	2007	2006
Discount rate	6.68%	6.30%	6.30%	6.30%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2008 and 2007, based upon a June 30, 2008 and 2007 measurement date.

	2008	2007
	(In thousands)	
Accumulated benefit obligation	\$ 83,871	\$ 86,976
Change in projected benefit obligation:		
Benefit obligation at beginning of year	\$ 92,350	\$ 87,499
Service cost	2,184	2,981
Interest cost	5,816	5,585
Actuarial loss (gain)	(3,634)	719
Benefits paid	(4,730)	(4,434)
Benefit obligation at end of year	91,986	92,350
Change in plan assets:		
Fair value of plan assets at beginning of year		
Employer contribution	4,730	4,434
Benefits paid	(4,730)	(4,434)

Fair value of plan assets at end of year

Reconciliation:

Funded status	(91,986)	(92,350)
Unrecognized prior service cost		
Unrecognized net loss		
Accrued pension cost	\$ (91,986)	\$ (92,350)

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Cost	Unrealized Holding Gain (In thousands)	Market Value
As of September 30, 2008:			
Domestic equity mutual funds	\$ 31,041	\$ 1,231	\$ 32,272
Foreign equity mutual funds	5,309	359	5,668
	\$ 36,350	\$ 1,590	\$ 37,940
As of September 30, 2007:			
Domestic equity mutual funds	\$ 32,781	\$ 2,793	\$ 35,574
Foreign equity mutual funds	4,618	1,855	6,473
	\$ 37,399	\$ 4,648	\$ 42,047

At September 30, 2008, we maintained an investment in one domestic equity mutual fund that was in an unrealized loss position as of September 30, 2008. Information concerning unrealized losses for our supplemental plan assets follows:

	Fair Value	Less Than 12 Months Unrealized Loss (In thousands)	Fair Value	12 Months or More Unrealized Loss
Domestic equity mutual fund	\$ 4,406	\$ (394)	\$	\$

Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary as of September 30, 2008.

Net periodic pension cost for the supplemental plans for fiscal 2008, 2007 and 2006 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2008	2007	2006
	(In thousands)		
Components of net periodic pension cost:			
Service cost	\$ 2,184	\$ 2,981	\$ 3,001
Interest cost	5,816	5,585	4,955
Amortization of transition asset			
Amortization of prior service cost	212	1,020	1,022
Recognized actuarial loss	1,222	1,482	2,789
Net periodic pension cost	\$ 9,434	\$ 11,068	\$ 11,767

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)***Supplemental Disclosures for Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets*

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2008 and 2007 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2008	2007
	(In thousands)	
Projected Benefit Obligation	\$ 91,986	\$ 92,350
Accumulated Benefit Obligation	83,871	86,976
Fair Value of Plan Assets		

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2009	\$ 29,146	\$ 8,047
2010	29,688	4,975
2011	29,896	5,913
2012	30,266	5,872
2013	30,845	5,974
2014-2018	164,866	33,971

Postretirement Benefits

We sponsor the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Atmos Retiree Medical Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent of this cost.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute \$12.7 million to our postretirement benefits

plan during fiscal 2009.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plan to ensure the assets funding the postretirement benefit plan are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plan.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2008 and 2007.

Security Class	Actual Allocation September 30	
	2008	2007
Diversified investment funds	98.1%	98.4%
Cash and cash equivalents	1.9%	1.6%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of June 30, 2008 and 2007 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of June 30, 2007, 2006 and 2005. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2008	2007	2008	2007	2006
Discount rate	6.68%	6.30%	6.30%	6.30%	5.00%
Expected return on plan assets	5.00%	5.00%	5.00%	5.20%	5.30%
Initial trend rate	8.00%	8.00%	8.00%	8.00%	9.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2014	2010	2011	2010	2010

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2008 and 2007, based upon a June 30, 2008 and 2007 measurement date.

	2008	2007
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	\$ 175,585	\$ 160,901
Service cost	13,367	11,228
Interest cost	11,648	10,561
Plan participants' contributions	2,879	3,605
Actuarial loss (gain)	1,401	470
Benefits paid	(11,008)	(11,305)
Subsidy payments	125	125
Benefit obligation at end of year	193,997	175,585
Change in plan assets:		
Fair value of plan assets at beginning of year	55,370	44,800
Actual return on plan assets	(8,782)	6,371
Employer contributions	9,613	11,899
Plan participants' contributions	2,879	3,605
Benefits paid	(11,008)	(11,305)
Fair value of plan assets at end of year	48,072	55,370
Reconciliation:		
Funded status	(145,925)	(120,215)
Unrecognized transition obligation		
Unrecognized prior service cost		
Unrecognized net loss		
Accrued postretirement cost	\$ (145,925)	\$ (120,215)

Net periodic postretirement cost for fiscal 2008, 2007 and 2006 is recorded as operating expense and included the components presented below.

Fiscal Year Ended September 30		
2008	2007	2006
(In thousands)		

Components of net periodic postretirement cost:

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Service cost	\$ 13,367	\$ 11,228	\$ 13,083
Interest cost	11,648	10,561	8,840
Expected return on assets	(2,861)	(2,388)	(2,187)
Amortization of transition obligation	1,511	1,512	1,511
Amortization of prior service cost		33	361
Recognized actuarial loss			1,280
Net periodic postretirement cost	\$ 23,665	\$ 20,946	\$ 22,888

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	\$ 3,980	\$ (3,301)
Effect on postretirement benefit obligation	\$ 22,620	\$ (19,115)

We are currently recovering other postretirement benefits costs through our regulated rates under SFAS 106 accrual accounting in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Kentucky/Mid-States Division and our Mississippi Division or have been included in a rate case and not disallowed. Management believes that accrual accounting in accordance with SFAS 106 is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

Estimated Future Benefit Payments

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
	(In thousands)			
2009	\$ 12,703	\$ 2,805	\$ 149	\$ 15,657
2010	10,262	3,199	77	13,538
2011	11,821	3,637		15,458
2012	13,352	4,092		17,444
2013	14,759	4,537		19,296
2014-2018	100,192	30,408		130,600

Defined Contribution Plans

As of September 30, 2008, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Marketing, LLC 401K Profit-Sharing Plan (the

AEM 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The Union 401K Plan covers substantially all Mississippi Division employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (the Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the Union 401K plan on the date of union membership. We match 50 percent of a participant's contribution in cash, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to \$8.9 million, \$8.3 million, and \$7.0 million for fiscal years 2008, 2007 and 2006. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for fiscal years 2008, 2007 or 2006. At September 30, 2008 and 2007, the Retirement Savings Plan held 3.4 percent and 3.1 percent of our outstanding common stock.

The AEM 401K Profit-Sharing Plan covers substantially all AEM employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to three percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEM 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEM 401K Profit-Sharing Plan are expensed as incurred and amounted to \$0.5 million, \$0.8 million and \$0.8 million for fiscal years 2008, 2007 and 2006.

9. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2008 and 2007:

	September 30	
	2008	2007
	(In thousands)	
Billed accounts receivable	\$ 411,225	\$ 325,721
Unbilled revenue	49,496	44,913
Other accounts receivable	31,731	25,659
Total accounts receivable	492,452	396,293

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Less: allowance for doubtful accounts	(15,301)	(16,160)
Net accounts receivable	\$ 477,151	\$ 380,133

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)*****Other current assets***

Other current assets as of September 30, 2008 and 2007 were comprised of the following accounts.

	September 30	
	2008	2007
	(In thousands)	
Assets from risk management activities	\$ 68,291	\$ 20,129
Deferred gas costs	55,103	14,797
Taxes receivable	22,052	33,002
Current deferred tax asset		4,664
Prepaid expenses	16,738	16,510
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	4,304	5,563
Other	15,158	13,551
Total	\$ 184,619	\$ 111,189

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2008 and 2007:

	September 30	
	2008	2007
	(In thousands)	
Production plant	\$ 21,958	\$ 12,578
Storage plant	150,984	149,164
Transmission plant	942,169	909,582
Distribution plant	3,870,606	3,627,729
General plant	597,460	560,400
Intangible plant	66,919	67,168
	5,650,096	5,326,621
Construction in progress	80,060	69,449
	5,730,156	5,396,070
Less: accumulated depreciation and amortization	(1,593,297)	(1,559,234)
Net property, plant and equipment	\$ 4,136,859	\$ 3,836,836

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)***Deferred charges and other assets*

Deferred charges and other assets as of September 30, 2008 and 2007 were comprised of the following accounts.

	September 30	
	2008	2007
	(In thousands)	
Pension plan assets in excess of plan obligations	\$ 7,997	\$ 55,785
Marketable securities	37,940	42,047
Regulatory assets	130,785	90,825
Deferred financing costs	35,378	39,866
Assets from risk management activities	5,473	5,535
Other	8,077	19,436
Total	\$ 225,650	\$ 253,494

Other current liabilities

Other current liabilities as of September 30, 2008 and 2007 were comprised of the following accounts.

	September 30	
	2008	2007
	(In thousands)	
Customer deposits	\$ 75,297	\$ 83,833
Accrued employee costs	42,956	35,188
Deferred gas costs	76,979	84,043
Accrued interest	52,366	51,523
Liabilities from risk management activities	58,914	21,339
Taxes payable	53,639	50,288
Pension and postretirement obligations	16,950	13,250
Regulatory cost of removal accrual	18,628	24,182
Current deferred tax liability	1,833	
Other	62,810	44,627
Total	\$ 460,372	\$ 408,273

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)***Deferred credits and other liabilities*

Deferred credits and other liabilities as of September 30, 2008 and 2007 were comprised of the following accounts.

	September 30	
	2008	2007
	(In thousands)	
Postretirement obligations	\$ 137,075	\$ 111,365
Retirement plan obligations	88,143	90,243
Customer advances for construction	17,814	18,173
Regulatory liabilities	5,639	7,503
Asset retirement obligation	5,883	8,966
Uncertain tax positions	6,731	
Liabilities from risk management activities	5,369	290
Other	727	7,002
Total	\$ 267,381	\$ 243,542

10. Earnings Per Share

Basic and diluted earnings per share for the fiscal years ended September 30 are calculated as follows:

	2008	2007	2006
	(In thousands, except per share data)		
Net income	\$ 180,331	\$ 168,492	\$ 147,737
Denominator for basic income per share weighted average common shares	89,385	86,975	80,731
Effect of dilutive securities:			
Restricted and other shares	790	620	551
Stock options	97	150	108
Denominator for diluted income per share weighted average common shares	90,272	87,745	81,390
Net income per share basic	\$ 2.02	\$ 1.94	\$ 1.83
Net income per share diluted	\$ 2.00	\$ 1.92	\$ 1.82

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2008, 2007 and 2006.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****11. Income Taxes**

The components of income tax expense from continuing operations for 2008, 2007 and 2006 were as follows:

	2008	2007	2006
	(In thousands)		
Current			
Federal	\$ 7,161	\$ 22,616	\$ 838
State	7,696	9,810	2,623
Deferred			
Federal	85,573	56,349	77,154
State	12,367	5,772	9,024
Investment tax credits	(424)	(455)	(486)
	\$ 112,373	\$ 94,092	\$ 89,153

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2008, 2007 and 2006 are set forth below:

	2008	2007	2006
	(In thousands)		
Tax at statutory rate of 35%	\$ 102,446	\$ 91,904	\$ 82,912
Common stock dividends deductible for tax reporting	(1,363)	(1,233)	(1,180)
Depreciation/amortization		(4,727)	
Tax exempt income		(1,890)	
State taxes (net of federal benefit)	12,523	10,253	7,570
Other, net	(1,233)	(215)	(149)
Income tax expense	\$ 112,373	\$ 94,092	\$ 89,153

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2008 and 2007 are presented below:

	2008	2007
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	\$ 16,305	\$ 15,047
Accruals not currently deductible for tax purposes	11,627	11,097
Customer advances	6,769	6,906
Nonqualified benefit plans	39,632	33,111
Postretirement benefits	46,319	40,984
Treasury lock agreement	6,806	8,735
Unamortized investment tax credit	345	506
Regulatory liabilities	911	966
Tax net operating loss and credit carryforwards	616	2,505
Other, net	543	3,976
Total deferred tax assets	129,873	123,833
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(534,607)	(426,772)
Pension funding	(25,777)	(30,557)
Gas cost adjustments	(5,362)	(12,547)
Regulatory assets	(568)	(1,131)
Cost capitalized for book purposes and expensed for tax purposes		(5,184)
Difference between book and tax on mark to market accounting	(6,694)	(11,766)
Other, net		(1,781)
Total deferred tax liabilities	(573,008)	(489,738)
Net deferred tax liabilities	\$ (443,135)	\$ (365,905)
SFAS No. 109 deferred credits for rate regulated entities	\$ 2,397	\$ 2,541

We have tax carryforwards relating to state net operating losses amounting to \$0.6 million. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2013 and 2027.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the

tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

We adopted the provisions of FIN 48 on October 1, 2007. As a result of adopting FIN 48, we determined that we had \$6.1 million of liabilities associated with uncertain tax positions. Of this amount, \$0.5 million was recognized as a result of adopting FIN 48 with an offsetting reduction to retained earnings.

Prior to October 1, 2007, the \$5.6 million liability previously recorded for uncertain tax positions was reflected on the consolidated balance sheet as a component of deferred income taxes. As a result of adopting FIN 48, we recorded a \$3.7 million liability as a component of other current liabilities and \$2.4 million as a component of deferred credits and other liabilities, with offsetting decreases to the deferred income tax liability.

As of September 30, 2008, we had recorded liabilities associated with uncertain tax positions totaling \$6.7 million. The realization of all of these tax benefits would reduce our income tax expense by approximately \$6.7 million.

The following table presents the changes in unrecognized tax benefits for the fiscal year ended September 30, 2008 (in thousands):

Total unrecognized tax benefits at October 1, 2007	\$ 6,156
Gross increases for current year's tax positions	
Gross increases for prior years' tax positions	5,081
Gross decreases for prior years' tax positions	(528)
Settlements	(3,978)
Total unrecognized tax benefits at September 30, 2008	\$ 6,731

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax benefit of \$1.2 million related to penalty and interest expenses during the fiscal year ended September 30, 2008.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2004.

12. Commitments and Contingencies***Litigation******Colorado-Kansas Division***

We are a defendant in a lawsuit originally filed by Quinque Operating Company, Tom Boles and Robert Ditto in September 1999 in the District Court of Stevens County, Kansas against more than 200 companies in the natural gas industry. The plaintiffs, who purport to represent a class of royalty owners, allege that the defendants have underpaid royalties on gas taken from wells situated on non-federal and non-Indian lands in Kansas, predicated upon allegations that the defendants' gas measurements were inaccurate. The plaintiffs have not specifically alleged an amount of

damages. We are also a defendant, along with over 50 other companies in the natural gas industry, in another proposed class action lawsuit filed in the same court by Will Price, Tom Boles and The Cooper Clarke Foundation in May 2003 involving similar allegations. We believe that the plaintiffs' claims are lacking in merit and we intend to vigorously defend these actions. While the results cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial condition, results of operations or cash flows. We are also a defendant in another lawsuit entitled *In Re Natural Gas Royalties Qui Tam Litigation*, involving similar allegations filed in June 1997 in the United States District Court for the District of Colorado, which was later transferred to the United States District Court for the District of Wyoming, where it was consolidated with approximately 50

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

additional lawsuits in October 1999. In October 2006, the District Court granted the defendants' motion to dismiss this lawsuit for lack of subject matter jurisdiction. The plaintiffs have appealed this dismissal order on which oral arguments were heard by the United States Court of Appeals for the Tenth Circuit in September 2008. The appeal has yet to be ruled on by the Tenth Circuit.

We are a party to other litigation and claims that have arisen in the ordinary course of our business. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City and Bristol, Tennessee, Keokuk, Iowa, Hannibal, Missouri, and Owensboro, Kentucky, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. Under current environmental protection laws and regulations, we may be responsible for response actions with respect to such materials if response actions are necessary. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa, Missouri, Kentucky and the United States Environmental Protection Agency.

We are a party to other environmental matters and claims that have arisen in the ordinary course of our business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2008, AEM was committed to purchase 55.8 Bcf within one year, 35.6 Bcf within one to three years and 0.5 Bcf after three years under indexed contracts. AEM is committed to purchase 1.5 Bcf within one year and less than 0.1 Bcf within one to three years under fixed price contracts with prices ranging from \$3.58 to \$13.20 per Mcf. Purchases under these contracts totaled \$3,075.0 million, \$2,065.1 million and \$2,124.3 million for 2008, 2007 and 2006.

Our natural gas distribution divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of September 30, 2008 are as follows (in thousands):

2009	\$ 418,949
2010	99,885
2011	9,569
2012	9,580
2013	9,068
Thereafter	2,978
	\$ 550,029

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the Commission) in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. We have responded timely to two sets of data requests received from the Commission and are fully cooperating with the Commission during this investigation.

Subsequent to responding to the second set of data requests, the Commission agreed to allow the Company to conduct our own internal investigation into compliance with the Commission's rules, and we will provide the results of this internal investigation to the Commission upon its completion. We currently are unable to predict the final outcome of this investigation or the potential impact it could have on our financial position, results of operations or cash flows.

On September 1, 2008, a Texas Railroad Commission rule, which is applicable to all natural gas distribution companies operating in Texas, became effective concerning the replacement of known compression couplings at pre-bent gas meter risers. Compliance with this rule should not have a significant impact on our West Texas Division but will require us to spend significant amounts of capital in our Mid-Tex Division. The completion date required by the Railroad Commission of Texas for the replacement of known compression couplings at pre-bent gas meter risers is November 2009 and the Mid-Tex Division is on target to meet this requirement. Compliance with this rule will require us to expend significant amounts of capital but these prudent and mandatory expenditures should be recoverable through our rates in the Mid-Tex Division. As a result, we anticipate no long-term adverse impact on our financial position, results of operations or cash flows.

13. Leases***Leasing Operations***

Atmos Power Systems, Inc. has constructed electric peaking power-generating plants and associated facilities and entered into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one

distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2008 and 2007, we had receivables of \$13.8 million and \$16.4 million and recognized income of \$1.3 million, \$1.5 million and \$1.7 million for

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

fiscal years 2008, 2007 and 2006. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts (In thousands)
2009	\$ 3,030
2010	2,973
2011	2,973
2012	2,973
2013	1,824
Thereafter	
Total minimum lease receipts	\$ 13,773

Capital and Operating Leases

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 20 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of \$1.3 million and \$4.6 million at September 30, 2008 and 2007. Accumulated depreciation for these capital leases totaled \$0.7 million and \$3.2 million at September 30, 2008 and 2007. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2008 were as follows:

	Capital Leases (In thousands)	Operating Leases (In thousands)
2009	\$ 186	\$ 18,374
2010	186	17,496
2011	186	16,429
2012	186	15,789
2013	186	15,135
Thereafter	822	97,094
Total minimum lease payments	1,752	\$ 180,317

Less amount representing interest	746
Present value of net minimum lease payments	\$ 1,006

Consolidated lease and rental expense amounted to \$14.2 million, \$11.3 million and \$11.4 million for fiscal 2008, 2007 and 2006.

14. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

with trade accounts receivable for the natural gas distribution segment is mitigated by the large number of individual customers and diversity in our customer base. The credit risk for our other segments is not significant.

Customer diversification also helps mitigate AEM's exposure to credit risk. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements, primarily consisting of letters of credit, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2008, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers, that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2008 and 2007.

	September 30, 2008	September 30, 2007
Investment grade	52%	53%
Non-investment grade	48%	47%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2008. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's.

Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

Natural Gas

	Natural Gas Distribution Segment⁽¹⁾	Marketing Segment (In thousands)	Consolidated
Investment grade counterparties	\$	\$ 42,220	\$ 42,220
Non-investment grade counterparties		4,696	4,696
	\$	\$ 46,916	\$ 46,916

⁽¹⁾ Counterparty risk for our natural gas distribution segment is minimized because hedging gains and losses are passed through to our customers.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****15. Supplemental Cash Flow Disclosures**

Supplemental disclosures of cash flow information for fiscal 2008, 2007 and 2006 are presented below.

	2008	2007 (In thousands)	2006
Cash paid for interest	\$ 139,958	\$ 151,616	\$ 149,031
Cash paid for income taxes	\$ 3,483	\$ 8,939	\$ 77,265

There were no significant noncash investing and financing transactions during fiscal 2008, 2007 and 2006. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

16. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage business as well as other nonregulated businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers primarily in the Midwest and Southeast. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

We operate the Company through the following four segments:

The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.

The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline Texas Division.

The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.

The *pipeline, storage and other segment*, which includes our nonregulated natural gas transmission and storage services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution

segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Summarized income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 30, 2008					
	Regulated		Pipeline,			
	Natural Gas	Transmission and Storage	Natural Gas Marketing	Storage and Other	Eliminations	Consolidated
	Distribution		(In thousands)			
Operating revenues from external parties	\$ 3,654,338	\$ 108,116	\$ 3,436,563	\$ 22,288	\$	\$ 7,221,305
Intersegment revenues	792	87,801	851,299	9,421	(949,313)	
	3,655,130	195,917	4,287,862	31,709	(949,313)	7,221,305
Purchased gas cost	2,649,064		4,194,841	3,396	(947,322)	5,899,979
Gross profit	1,006,066	195,917	93,021	28,313	(1,991)	1,321,326
Operating expenses						
Operation and maintenance	389,244	77,439	30,903	4,983	(2,335)	500,234
Depreciation and amortization	177,205	19,899	1,546	1,792		200,442
Taxes, other than income	178,452	8,834	4,180	1,289		192,755
Total operating expenses	744,901	106,172	36,629	8,064	(2,335)	893,431
Operating income	261,165	89,745	56,392	20,249	344	427,895
Miscellaneous income	9,689	1,354	2,022	8,428	(18,762)	2,731
Interest charges	117,933	27,049	9,036	2,322	(18,418)	137,922
Income before income taxes	152,921	64,050	49,378	26,355		292,704
Income tax expense	60,273	22,625	19,389	10,086		112,373
Net income	\$ 92,648	\$ 41,425	\$ 29,989	\$ 16,269	\$	\$ 180,331
Capital expenditures	\$ 386,542	\$ 75,071	\$ 340	\$ 10,320	\$	\$ 472,273

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

	Year Ended September 30, 2007					
	Regulated		Pipeline,			
	Natural Gas	Transmission and Storage	Natural Gas	Storage and Other		
	Distribution		Marketing		Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	\$ 3,358,147	\$ 84,344	\$ 2,432,280	\$ 23,660	\$	\$ 5,898,431
Intersegment revenues	618	78,885	719,050	9,740	(808,293)	
	3,358,765	163,229	3,151,330	33,400	(808,293)	5,898,431
Purchased gas cost	2,406,081		3,047,019	792	(805,543)	4,648,349
Gross profit	952,684	163,229	104,311	32,608	(2,750)	1,250,082
Operating expenses						
Operation and maintenance	379,175	56,231	26,480	4,581	(3,094)	463,373
Depreciation and amortization	177,188	18,565	1,536	1,574		198,863
Taxes, other than income	171,845	8,603	1,255	1,163		182,866
Impairment of long-lived assets	3,289			3,055		6,344
Total operating expenses	731,497	83,399	29,271	10,373	(3,094)	851,446
Operating income	221,187	79,830	75,040	22,235	344	398,636
Miscellaneous income	8,945	2,105	6,434	8,173	(16,473)	9,184
Interest charges	121,626	27,917	5,767	6,055	(16,129)	145,236
Income before income taxes	108,506	54,018	75,707	24,353		262,584
Income tax expense	35,223	19,428	29,938	9,503		94,092
Net income	\$ 73,283	\$ 34,590	\$ 45,769	\$ 14,850	\$	\$ 168,492
Capital expenditures	\$ 327,442	\$ 59,276	\$ 1,069	\$ 4,648	\$	\$ 392,435

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

	Year Ended September 30, 2006					
	Natural Gas	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	Distribution					
	(In thousands)					
Operating revenues from external parties	\$ 3,649,851	\$ 69,582	\$ 2,418,856	\$ 14,074	\$	\$ 6,152,363
Intersegment revenues	740	71,551	737,668	11,500	(821,459)	
	3,650,591	141,133	3,156,524	25,574	(821,459)	6,152,363
Purchased gas cost	2,725,534		3,025,897	1,080	(816,718)	4,935,793
Gross profit	925,057	141,133	130,627	24,494	(4,741)	1,216,570
Operating expenses						
Operation and maintenance	357,519	51,577	22,223	7,077	(4,978)	433,418
Depreciation and amortization	164,493	18,012	1,834	1,257		185,596
Taxes, other than income	178,204	8,218	4,335	1,236		191,993
Impairment of long-lived assets	22,947					22,947
Total operating expenses	723,163	77,807	28,392	9,570	(4,978)	833,954
Operating income	201,894	63,326	102,235	14,924	237	382,616
Miscellaneous income (expense)	9,506	(153)	2,598	6,858	(17,928)	881
Interest charges	126,489	22,787	8,510	6,512	(17,691)	146,607
Income before income taxes	84,911	40,386	96,323	15,270		236,890
Income tax expense	31,909	13,839	37,757	5,648		89,153
Net income	\$ 53,002	\$ 26,547	\$ 58,566	\$ 9,622	\$	\$ 147,737
Capital expenditures	\$ 307,742	\$ 114,873	\$ 909	\$ 1,800	\$	\$ 425,324

The following table summarizes our revenues by products and services for the fiscal year ended September 30.

	2008	2007	2006
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	\$ 2,131,447	\$ 1,982,801	\$ 2,068,736
Commercial	1,077,056	970,949	1,061,783
Industrial	212,531	195,060	276,186
Public authority and other	137,821	114,298	144,600
Total gas sales revenues	3,558,855	3,263,108	3,551,305
Transportation revenues	59,712	59,195	61,475
Other gas revenues	35,771	35,844	37,071
Total natural gas distribution revenues	3,654,338	3,358,147	3,649,851
Regulated transmission and storage revenues	108,116	84,344	69,582
Natural gas marketing revenues	3,436,563	2,432,280	2,418,856
Pipeline, storage and other revenues	22,288	23,660	14,074
Total operating revenues	\$ 7,221,305	\$ 5,898,431	\$ 6,152,363

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Balance sheet information at September 30, 2008 and 2007 by segment is presented in the following tables:

	September 30, 2008					
	Natural	Regulated	Natural	Pipeline,		
	Gas	Transmission	Gas	Storage		
	Distribution	and	Marketing	and Other	Eliminations	Consolidated
		Storage	(In thousands)			
ASSETS						
Property, plant and equipment, net	\$ 3,483,556	\$ 585,160	\$ 7,520	\$ 60,623	\$	\$ 4,136,859
Investment in subsidiaries	463,158		(2,096)		(461,062)	
Current assets						
Cash and cash equivalents	30,878		9,120	6,719		46,717
Assets from risk management activities			69,008	20,239	(20,956)	68,291
Other current assets	774,933	18,396	411,648	56,791	(91,672)	1,170,096
Intercompany receivables	578,833			135,795	(714,628)	
Total current assets	1,384,644	18,396	489,776	219,544	(827,256)	1,285,104
Intangible assets			2,088			2,088
Goodwill	569,920	132,367	24,282	10,429		736,998
Noncurrent assets from risk management activities			5,473			5,473
Deferred charges and other assets	195,985	11,212	1,182	11,798		220,177
	\$ 6,097,263	\$ 747,135	\$ 528,225	\$ 302,394	\$ (1,288,318)	\$ 6,386,699
CAPITALIZATION AND LIABILITIES						
Shareholders equity	\$ 2,052,492	\$ 130,144	\$ 114,559	\$ 218,455	\$ (463,158)	\$ 2,052,492
Long-term debt	2,119,267			525		2,119,792
Total capitalization	4,171,759	130,144	114,559	218,980	(463,158)	4,172,284
Current liabilities						
Current maturities of long-term debt				785		785
Short-term debt	385,592		6,500		(41,550)	350,542
Liabilities from risk management activities	58,566		20,688	616	(20,956)	58,914

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Other current liabilities	538,777	7,053	236,217	62,796	(47,997)	796,846
Intercompany payables		543,384	171,244		(714,628)	
Total current liabilities	982,935	550,437	434,649	64,197	(825,131)	1,207,087
Deferred income taxes	384,860	62,720	(21,936)	15,687	(29)	441,302
Noncurrent liabilities from risk management activities	5,111		258			5,369
Regulatory cost of removal obligation	298,645					298,645
Deferred credits and other liabilities	253,953	3,834	695	3,530		262,012
	\$ 6,097,263	\$ 747,135	\$ 528,225	\$ 302,394	\$ (1,288,318)	\$ 6,386,699

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

	September 30, 2007					
	Natural	Regulated	Natural	Pipeline,		
	Gas	Transmission	Gas	Storage		
	Distribution	and	Marketing	and Other	Eliminations	Consolidated
		Storage	(In thousands)			
ASSETS						
Property, plant and equipment, net	\$ 3,251,144	\$ 531,921	\$ 7,850	\$ 45,921	\$	\$ 3,836,836
Investment in subsidiaries	396,474		(2,096)		(394,378)	
Current assets						
Cash and cash equivalents	28,881		31,703	141		60,725
Assets from risk management activities			25,063	12,947	(17,881)	20,129
Other current assets	643,353	20,065	337,169	76,731	(90,997)	986,321
Intercompany receivables	536,985			114,300	(651,285)	
Total current assets	1,209,219	20,065	393,935	204,119	(760,163)	1,067,175
Intangible assets			2,716			2,716
Goodwill	567,775	132,490	24,282	10,429		734,976
Noncurrent assets from risk management activities			5,535			5,535
Deferred charges and other assets	227,869	4,898	1,279	13,913		247,959
	\$ 5,652,481	\$ 689,374	\$ 433,501	\$ 274,382	\$ (1,154,541)	\$ 5,895,197
CAPITALIZATION AND LIABILITIES						
Shareholders equity	\$ 1,965,754	\$ 88,719	\$ 107,090	\$ 200,665	\$ (396,474)	\$ 1,965,754
Long-term debt	2,125,007			1,308		2,126,315
Total capitalization	4,090,761	88,719	107,090	201,973	(396,474)	4,092,069
Current liabilities						
Current maturities of long-term debt	1,250			2,581		3,831
Short-term debt	187,284		30,000		(66,685)	150,599
Liabilities from risk management activities	21,053		18,167		(17,881)	21,339
Other current liabilities	519,642	6,394	185,072	53,297	(22,216)	742,189
Intercompany payables		550,184	101,101		(651,285)	

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Total current liabilities	729,229	556,578	334,340	55,878	(758,067)	917,958
Deferred income taxes	326,518	40,565	(8,925)	12,411		370,569
Noncurrent liabilities from risk management activities			290			290
Regulatory cost of removal obligation	271,059					271,059
Deferred credits and other liabilities	234,914	3,512	706	4,120		243,252
	\$ 5,652,481	\$ 689,374	\$ 433,501	\$ 274,382	\$ (1,154,541)	\$ 5,895,197

Table of Contents**ATMOS ENERGY CORPORATION****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****17. Selected Quarterly Financial Data (Unaudited)**

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the Results of Operations discussion included in the Management's Discussion and Analysis of Financial Condition and Results of Operations section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2008:				
Operating revenues				
Natural gas distribution	\$ 928,177	\$ 1,521,856	\$ 676,639	\$ 528,458
Regulated transmission and storage	45,046	51,440	46,286	53,145
Natural gas marketing	840,717	1,128,653	1,189,722	1,128,770
Pipeline, storage and other	6,727	10,022	3,880	11,080
Intersegment eliminations	(163,157)	(227,986)	(277,382)	(280,788)
	1,657,510	2,483,985	1,639,145	1,440,665
Gross profit	369,638	434,394	246,222	271,072
Operating income	158,509	211,143	20,709	37,534
Net income (loss)	73,803	111,534	(6,588)	1,582
Net income (loss) per basic share	\$ 0.83	\$ 1.25	\$ (0.07)	\$ 0.02
Net income (loss) per diluted share	\$ 0.82	\$ 1.24	\$ (0.07)	\$ 0.02
Fiscal year 2007:				
Operating revenues				
Natural gas distribution	\$ 964,244	\$ 1,461,033	\$ 548,251	\$ 385,237
Regulated transmission and storage	39,872	46,068	36,707	40,582
Natural gas marketing	711,694	795,041	854,167	790,428
Pipeline, storage and other	11,333	14,077	2,073	5,917
Intersegment eliminations	(124,510)	(240,637)	(223,046)	(220,100)
	1,602,633	2,075,582	1,218,152	1,002,064
Gross profit	375,592	428,686	228,016	217,788
Operating income	171,160	209,012	7,731	10,733
Net income (loss)	81,261	106,505	(13,360)	(5,914)
Net income (loss) per basic share	\$ 0.98	\$ 1.21	\$ (0.15)	\$ (0.07)
Net income (loss) per diluted share	\$ 0.97	\$ 1.20	\$ (0.15)	\$ (0.07)

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ITEM 9. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.*

None.

ITEM 9A. *Controls and Procedures.*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2008 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2008, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ ROBERT W. BEST

/s/ JOHN P. REDDY

Robert W. Best
Chairman and Chief Executive Officer

John P. Reddy
Senior Vice President and Chief Financial Officer

November 18, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2008 and 2007, and the related statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2008 of Atmos Energy Corporation and our report dated November 18, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 18, 2008

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Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009. Information regarding executive officers is included in Part I of this Annual Report on Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at www.atmosenergy.com under "Corporate Governance". In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance".

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 4, 2009.

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PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.5(a) through 10.12(f) are management contracts or compensatory plans or arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY
John P. Reddy
*Senior Vice President
and Chief Financial Officer*

Date: November 19, 2008

Table of Contents**POWER OF ATTORNEY**

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Robert W. Best and John P. Reddy, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ ROBERT W. BEST	Chairman and Chief Executive Officer	November 19, 2008
Robert W. Best		
/s/ JOHN P. REDDY	Senior Vice President and Chief Financial Officer	November 19, 2008
John P. Reddy		
/s/ F.E. MEISENHEIMER	Vice President and Controller (Principal Accounting Officer)	November 19, 2008
F.E. Meisenheimer		
/s/ TRAVIS W. BAIN, II	Director	November 19, 2008
Travis W. Bain, II		
/s/ DAN BUSBEE	Director	November 19, 2008
Dan Busbee		
/s/ RICHARD W. CARDIN	Director	November 19, 2008
Richard W. Cardin		
/s/ RICHARD W. DOUGLAS	Director	November 19, 2008
Richard W. Douglas		
/s/ RUBEN E. ESQUIVEL	Director	November 19, 2008
Ruben E. Esquivel		

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/s/ THOMAS J. GARLAND	Director	November 19, 2008
Thomas J. Garland		
/s/ RICHARD K. GORDON	Director	November 19, 2008
Richard K. Gordon		
/s/ THOMAS C. MEREDITH	Director	November 19, 2008
Thomas C. Meredith		
/s/ PHILLIP E. NICHOL	Director	November 19, 2008
Phillip E. Nichol		
/s/ NANCY K. QUINN	Director	November 19, 2008
Nancy K. Quinn		

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/s/ STEPHEN R. SPRINGER	Director	November 19, 2008
Stephen R. Springer		
/s/ CHARLES K. VAUGHAN	Director	November 19, 2008
Charles K. Vaughan		
/s/ RICHARD WARE II	Director	November 19, 2008
Richard Ware II		

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Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2008

	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Charged to Other Accounts (In thousands)	Deductions	Balance at End of Period
2008					
Allowance for doubtful accounts	\$ 16,160	\$ 15,655	\$	\$ 16,514 ⁽¹⁾	\$ 15,301
2007					
Allowance for doubtful accounts	\$ 13,686	\$ 19,718	\$	\$ 17,244 ⁽¹⁾	\$ 16,160
2006					
Allowance for doubtful accounts	\$ 15,613	\$ 21,819	\$	\$ 23,746 ⁽¹⁾	\$ 13,686

⁽¹⁾ Uncollectible accounts written off.

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Exhibit Number	Description	Page Number or Incorporation by Reference to
	<i>Articles of Incorporation and Bylaws</i>	
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005)	Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of May 2, 2007)	Exhibit 3.1 to Form 8-K dated May 2, 2007 (File No. 1-10042)
	<i>Instruments Defining Rights of Security Holders</i>	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit (4)(b) to Form 10-K for fiscal year ended September 30, 1988 (File No. 1-10042)
4.2(a)	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.2(b)	First Supplemental Indenture dated as of July 29, 1997 between Atmos Energy Corporation and First Trust National Association, as successor to Bank of America Illinois, Trustee	Exhibit 4.11(b) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6(a)	Debenture Certificate for the 63/4% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.6(b)	Global Security for the 73/8% Senior Notes due 2011	Exhibit 99.2 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.6(c)	Global Security for the 51/8% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for the fiscal year ended September 30, 2004 (File No. 1-10042)
4.6(d)	Global Security for the 4.00% Senior Notes due 2009	Exhibit 10(2)(e) to Form 10-K for the fiscal year ended September 30, 2004 (File No. 1-10042)
4.6(e)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for the fiscal year ended September 30, 2004 (File No. 1-10042)
4.6(f)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for the fiscal year ended September 30, 2004 (File No. 1-10042)
4.6(g)	Global Security for the 6.35% Senior Notes due 2017	Exhibit 4.2 to Form 8-K dated June 11, 2007 (File No. 1-10042)

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Exhibit Number	Description	Page Number or Incorporation by Reference to
	<i>Material Contracts</i>	
10.1	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)
10.2	Revolving Credit Agreement (5 Year Facility), dated as of December 15, 2006, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Wachovia Bank, N.A. as Syndication Agent and Bank of America, N.A., JPMorgan Chase Bank, N.A., and the Royal Bank of Scotland plc as Co-Documentation Agents, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated December 15, 2006 (File No. 1-10042)
10.3	Revolving Credit Agreement (364 Day Facility), dated as of October 29, 2008, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Bank of America, N.A., as Syndication Agent, U.S. Bank National Association as Documentation Agent and Wells Fargo Bank, N.A. as Managing Agent, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated October 29, 2008 (File No. 1-10042)
10.4(a)	Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated March 30, 2005 (File No. 1-10042)
10.4(b)	First Amendment, dated as of November 28, 2005, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Societe Generale, and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated November 28, 2005 (File No. 1-10042)
10.4(c)	Second Amendment, dated as of March 31, 2006, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Societe Generale and the other financial	Exhibit 10.1 to Form 8-K dated March 31, 2006 (File No. 1-10042)

10.4(d)	institutions which may become parties thereto Third Amendment, dated as of March 30, 2007, to the Uncommitted Second Amended and Restated Credit Agreement, dated as of March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Societe Generale and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated March 30, 2007 (File No. 1-10042)
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Exhibit Number	Description	Page Number or Incorporation by Reference to
10.4(e)	Fourth Amendment, dated as of March 31, 2008, to the Uncommitted Second Amended and Restated Credit Agreement, dated as of March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Societe Generale and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated March 31, 2008 (File No. 1-10042)
10.4(f)	Intercreditor Agreement, dated as of March 31, 2008, among Fortis Capital Corp. and the other financial institutions which may become parties thereto	Exhibit 10.2 to Form 8-K dated March 31, 2008 (File No. 1-10042)
	<i>Executive Compensation Plans and Arrangements</i>	
10.5(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement Tier I	
10.5(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement Tier II	
10.6(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.6(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(a)*	Description of Financial and Estate Planning Program	Exhibit 10.25(b) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(b)*	Description of Sporting Events Program	Exhibit 10.26(c) to Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042)
10.8(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	
10.8(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan, (An Amendment and Restatement of the Performance-Based Supplemental Executive Benefits Plan), Effective Date August 7, 2007	
10.8(c)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.8(d)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.9(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.9(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)

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10.9(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.10*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors	

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Exhibit Number	Description	Page Number or Incorporation by Reference to
10.11*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan (Amended and Restated as of November 12, 1997)	Exhibit 10.28 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.12(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	Exhibit 10.2 to Form 10-Q for quarter ended March 31, 2007 (File No. 1-10042)
10.12(b)*	Amendment No. 1 to Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	
10.12(c)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.12(d)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.12(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.12(f)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated August 8, 2007)	
12	Statement of computation of ratio of earnings to fixed charges	
	<i>Other Exhibits, as indicated</i>	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2008
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	

* This exhibit constitutes a management contract or compensatory plan, contract, or arrangement.

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.