ATMOS ENERGY CORP
Form 10-K
November 29, 2007

Table of Contents

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

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended September 30, 2007**
	OR
o	**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)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**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 þ No o

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 o No þ

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 þ No o

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. þ

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

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, 2007, was $2,715,259,243.

As of November 20, 2007, the registrant had 89,749,755 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 6, 2008 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APB	Accounting Principles Board
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
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
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
MVG	Mississippi Valley Gas Company, which was acquired December 3, 2002
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor s Corporation
SEC	United States Securities and Exchange Commission
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

PART I

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

ITEM 1. *Business*

Overview

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. We are one of the country s largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2007, we distributed 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 covered service areas in 12 states. 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.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties.

We were organized under the laws of Texas in 1983 as Energas Company for the purpose of owning and operating the natural gas distribution business of Pioneer Corporation in Texas. In September 1988, we changed our name to Atmos Energy Corporation. As a result of the merger with United Cities Gas Company in July 1997, we also became incorporated in Virginia.

Operating Segments

Through August 31, 2007, our operations were divided into four segments:

- the *utility segment*, which included our regulated natural gas distribution and related sales operations,
- the *natural gas marketing segment*, which included a variety of nonregulated natural gas management services,
- the *pipeline and storage segment*, which included our regulated and nonregulated natural gas transmission and storage services and
- the *other nonutility segment*, which included all of our other nonregulated nonutility operations.

During the fourth quarter of fiscal 2007, we completed a series of organizational changes and began reporting the results of our operations under the following new segments, effective September 1, 2007:

- The *natural gas distribution segment*, formerly referred to as the utility segment, includes our regulated natural gas distribution and related sales operations.

The *regulated transmission and storage segment* includes the regulated pipeline and storage operations of our Atmos Pipeline Texas Division. These operations were previously included in the former pipeline and storage segment.

The *natural gas marketing segment* remains unchanged and includes a variety of nonregulated natural gas management services.

The *pipeline, storage and other segment* primarily is comprised of our nonregulated natural gas transmission and storage services, which were previously included in the former pipeline and storage segment.

Table of Contents

Strategy

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.

Over the last five fiscal years, we have primarily grown through two significant acquisitions, our acquisition in December 2002 of Mississippi Valley Gas Company (MVG) and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas).

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth 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 addition, we have focused on regulatory rate proceedings to increase revenue to recover rising costs and mitigated weather-related risks through weather-normalized rates in most of our service areas. We have also strengthened our nonregulated businesses by increasing gross profit margins, expanding commercial opportunities in our regulated transmission and storage segment 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.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment consisted of the following six regulated divisions during the year ended September 30, 2007:

- 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.

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.

The effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which are now approved by the regulatory authorities for over 90 percent of residential and commercial meters in our service areas. WNA allows 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.

Table of Contents

As of September 30, 2007 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

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 2007 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 2007 was on February 15, 2007, when sales to customers reached approximately 3.4 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 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

Table of Contents

September 30, 2007, we held 1,106 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 communities in the north-central, eastern and western parts of Texas, including the Dallas/Fort Worth Metroplex. This division currently operates under one system-wide rate structure. However, 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. This division participates in Texas Gas Reliability Infrastructure Program (GRIP), which allows us to include in rate base annually approved capital costs incurred in the prior calendar year. The program also requires us to 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, which is less than 20 miles from downtown 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. Similarly, the West Texas Division also participates in GRIP, which requires us to file a complete rate case at least once every five years.

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.

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division serves approximately 170 communities throughout Colorado and Kansas and in the southwestern corner of Missouri, including Olathe, Kansas, and Greeley, Colorado. Olathe is a southern suburb of Kansas City, near the Missouri border. Greeley is located 20 miles outside of Denver. We update our rates in this division through periodic formal rate filings made with each state s public service commission.

Table of Contents

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.

Division	Jurisdiction	Effective Date of Last Rate Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Return on Equity(1)
Atmos Pipeline Texas	Texas	5/24/04	$417,111	8.258%	10.00%
Colorado-Kansas	Colorado	7/1/05	84,711	8.95%	11.25%
	Kansas	3/1/04	(2)	(2)	(2)
Kentucky/Mid-States	Georgia	12/20/05	62,380	7.57%	10.13%
	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%
	Virginia	8/1/04	30,672	8.46% - 8.96%	9.50% - 10.50%
Louisiana	Trans LA	4/1/07	96,848	(2)	10.00% - 10.80%
	LGS	7/1/07	207,587	(2)	10.40%
Mid-Tex	Texas	4/1/07	1,043,857	7.903%	10.00%
Mississippi	Mississippi	1/1/05	196,801	8.23%	9.80%
West Texas	Amarillo	9/1/03	36,844	9.88%	12.00%
	Lubbock	3/1/04	43,300	9.15%	11.25%
	West Texas	5/1/04	87,500	8.77%	10.50%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider(3)	WNA	Performance-Based Rate Program(4)	Customer Meters
Atmos Pipeline Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	52/48	No	No	No	109,860
	Kansas	(2)	Yes	Yes	No	127,824
Kentucky/Mid-States	Georgia	55/45	No	Yes	Yes	70,606
	Illinois	67/33	No	No	No	23,342
	Iowa	57/43	No	No	No	4,455
	Kentucky	(2)	No	Yes	Yes	177,988
	Missouri	(2)	No	No(5)	No	59,672
	Tennessee	56/44	No	Yes	Yes	133,715
	Virginia	52/48	Yes	Yes	No	23,721
Louisiana	Trans LA	52/48	No	Yes	No	79,985
	LGS	52/48	No	Yes	No	277,497
Mid-Tex	Texas	52/48	No	Yes	No	1,518,119
Mississippi	Mississippi	47/53	No	Yes	No	270,980
West Texas	Amarillo	50/50	Yes	Yes	No	69,772

Lubbock	50/50	No	Yes	No	73,672
West Texas	50/50	No	Yes	No	165,919

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the last base rate case 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.

Table of Contents

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

(4) 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 cost savings.

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

Natural Gas Distribution Sales and Statistical Data

	Year Ended September 30				
	2007	**2006**	**2005[1]**	**2004**	**2003[1]**
METERS IN SERVICE, end of year					
Residential	2,893,543	2,886,042	2,862,822	1,506,777	1,498,586
Commercial	272,081	275,577	274,536	151,381	151,008
Industrial	2,339	2,661	2,715	2,436	3,799
Agricultural	10,991	8,714	9,639	8,397	9,514
Public authority and other	8,173	8,205	8,128	10,145	9,891
Total meters	3,187,127	3,181,199	3,157,840	1,679,136	1,672,798
INVENTORY STORAGE BALANCE Bcf	58.0	59.9	54.7	27.4	23.9
HEATING DEGREE DAYS[2]					
Actual (weighted average)	2,879	2,527	2,587	3,271	3,473
Percent of normal	100%	87%	89%	96%	101%
SALES VOLUMES MMcf[3]					
Gas Sales Volumes					
Residential	166,612	144,780	162,016	92,208	97,953
Commercial	95,514	87,006	92,401	44,226	45,611
Industrial	22,914	26,161	29,434	22,330	23,738
Agricultural	3,691	5,629	3,348	4,642	7,884
Public authority and other	8,596	8,457	9,084	9,813	9,326
Total gas sales volumes	297,327	272,033	296,283	173,219	184,512
Transportation volumes	135,109	126,960	122,098	87,746	70,159
Total throughput	432,436	398,993	418,381	260,965	254,671
OPERATING REVENUES (000 $)[3]					
Gas Sales Revenues					

Residential	$ 1,982,801	$ 2,068,736	$ 1,791,172	$ 923,773	$ 873,375
Commercial	970,949	1,061,783	869,722	400,704	367,961
Industrial	195,060	276,186	229,649	155,336	151,969
Agricultural	28,023	40,664	27,889	31,851	48,625
Public authority and other	86,275	103,936	86,853	77,178	65,921
Total gas sales revenues	3,263,108	3,551,305	3,005,285	1,588,842	1,507,851
Transportation revenues	59,813	62,215	59,996	31,714	30,461
Other gas revenues	35,844	37,071	37,859	17,172	15,770
Total operating revenues	$ 3,358,765	$ 3,650,591	$ 3,103,140	$ 1,637,728	$ 1,554,082
Average transportation revenue per Mcf	$ 0.44	$ 0.49	$ 0.49	$ 0.36	$ 0.43
Average cost of gas per Mcf sold	$ 8.09	$ 10.02	$ 7.41	$ 6.55	$ 5.76
Employees	4,472	4,402	4,327	2,742	2,817

See footnotes following these tables.

Table of Contents

Natural Gas Distribution Sales and Statistical Data By Division

	Year Ended September 30, 2007							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado- Kansas	Other[4]	Tota
RS IN CE								
tial	1,398,274	434,529	334,467	270,557	240,073	215,643		2,893
rcial	119,660	54,964	23,015	25,460	27,461	21,521		272
al	185	927		521	619	87		2
tural				10,685		306		10
uthority and		2,623		2,140	2,827	583		8
	1,518,119	493,043	357,482	309,363	270,980	238,140		3,187
NG DEGREE)								
	2,332	3,831	1,638	3,537	2,759	5,732		2
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
rcial	50,752	16,137	7,138	7,671	6,859	6,957		95
al	3,946	7,439		3,521	7,672	336		22
tural				3,079		612		3
uthority and		1,454		2,297	3,386	1,459		8
	132,838	50,930	20,430	35,450	31,231	26,448		297
rtation volumes	49,337	46,852	6,841	21,709	2,072	8,298		135
roughput	182,175	97,782	27,271	57,159	33,303	34,746		432
ATING IN (000 s)[3]	$ 433,279	$ 151,442	$ 108,908	$ 90,285	$ 94,866	$ 73,904	$	$ 952
ATING NSES (000 s)[3]								
on and ance	$ 171,416	$ 61,029	$ 34,805	$ 34,187	$ 47,318	$ 30,026	$ 394	$ 379
ation and ation	$ 82,524	$ 34,439	$ 20,941	$ 14,026	$ 10,886	$ 14,372	$	$ 177
other than	$ 107,476	$ 13,813	$ 8,969	$ 21,036	$ 13,437	$ 7,114	$	$ 171
nent of ed assets	$ 3,289	$	$	$	$	$	$	$ 3

ATING ME (000 s)[(3)]	$ 68,574	$ 42,161	$ 44,193	$ 21,036	$ 23,225	$ 22,392	$ (394)	$ 221
AL NDITURES	$ 140,037	$ 59,641	$ 40,752	$ 27,031	$ 20,643	$ 21,395	$ 17,943	$ 327
ERTY, PLANT QUIPMENT, 00 s)	$ 1,356,453	$ 656,920	$ 345,535	$ 258,622	$ 241,796	$ 264,629	$ 127,189	$ 3,251
R STICS, at year								
f pipe	28,324	12,081	8,216	14,603	6,496	6,642		76
ees	1,415	633	422	340	409	269	984	4

See footnotes following these tables.

Table of Contents

	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado- Kansas	Other[4]	Tota
	Year Ended September 30, 2006							
RS IN CE								
tial	1,390,450	436,406	330,694	273,520	241,406	213,566		2,886
rcial	122,263	54,914	23,108	25,984	27,868	21,440		275
al	205	921		808	643	84		2
tural				8,402		312		8
uthority and		2,671		2,166	2,825	543		8
	1,512,918	494,912	353,802	310,880	272,742	235,945		3,181
NG DEGREE 2)								
	1,697	3,932	1,319	3,561	2,757	5,466		2
of normal	72%	98%	78%	100%	102%	99%		
VOLUMES)								
es Volumes								
tial	65,012	24,314	12,131	15,609	12,601	15,113		144
rcial	45,558	15,854	6,944	6,309	6,440	5,901		87
al	4,784	8,775		3,933	8,250	419		26
tural				5,010		619		5
uthority and		1,463		1,962	3,642	1,390		8
	115,354	50,406	19,075	32,823	30,933	23,442		272
rtation volumes	47,608	46,525	6,310	15,135	1,702	9,680		126
roughput	162,962	96,931	25,385	47,958	32,635	33,122		398
ATING IN (000 s)[3]	$ 412,334	$ 157,013	$ 98,502	$ 93,693	$ 92,515	$ 71,000	$	$ 925
ATING NSES (000 s)[3]								
on and ance	$ 154,412	$ 58,022	$ 40,741	$ 33,332	$ 44,533	$ 28,235	$ (1,756)	$ 357
ation and ation	$ 74,375	$ 33,808	$ 21,201	$ 13,690	$ 10,596	$ 13,578	$ (2,755)	$ 164
other than	$ 111,844	$ 15,290	$ 8,788	$ 21,509	$ 14,110	$ 6,663	$	$ 178
nent of ed assets	$	$	$	$ 22,947	$	$	$	$ 22
ATING IE (000 s)[3]	$ 71,703	$ 49,893	$ 27,772	$ 2,215	$ 23,276	$ 22,524	$ 4,511	$ 201

AL NDITURES	$ 134,762	$ 54,952	$ 32,218	$ 27,374	$ 15,389	$ 19,466	$ 23,581	$ 307
RTY, PLANT QUIPMENT, 00 s)	$ 1,262,516	$ 627,875	$ 328,310	$ 253,086	$ 226,690	$ 252,584	$ 132,240	$ 3,083
R STICS, at year								
f pipe	27,856	11,952	8,214	14,831	6,415	6,601		75
ees	1,458	636	412	341	437	263	855	4

Notes to preceding tables:

(1) The operational and statistical information includes the operations of the Mississippi Division since the December 3, 2002 acquisition date and 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 unit, which provides administrative and other support to the Company. Certain costs incurred by this unit are not allocated.

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. The Atmos Pipeline Texas 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.

Regulated Transmission and Storage Sales and Statistical Data

	Year Ended September 30				
	2007	**2006**	**2005**	**2004**[(1)]	**2003**[(1)]
CUSTOMERS, end of year					
Industrial	65	67	66		
Other	196	178	191		
Total	261	245	257		
PIPELINE TRANSPORTATION VOLUMES MMcf[(2)]	699,006	581,272	554,452		
OPERATING REVENUES (000 s)[(2)]	$ 163,229	$ 141,133	$ 142,952		
Employees, at year end	54	85	78		

(1) Atmos Pipeline Texas was acquired on October 1, 2004, the first day of our fiscal 2005 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), a wholly-owned subsidiary of AEC, which operates in 22 states. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers primarily in the southeastern and midwestern states and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana divisions. These services primarily consist 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 derivative instruments. We use proprietary and customer-owned transportation and storage assets to provide the various services our customers request. 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.

To optimize the storage and transportation capacity we own or control, we 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. Additionally, we engage 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 contracts at favorable prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, 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 from 30 days to two years.

Natural Gas Marketing Sales and Statistical Data

	Year Ended September 30				
	2007	**2006**	**2005**	**2004**	**2003**
CUSTOMERS, end of year					
Industrial	677	679	559	638	644
Municipal	68	73	69	80	94
Other	281	289	211	237	202
Total	1,026	1,041	839	955	940
INVENTORY STORAGE BALANCE Bcf	19.3	15.3	8.2	5.2	17.6
NATURAL GAS MARKETING SALES VOLUMES MMcf[1]	423,895	336,516	273,201	265,090	294,785
OPERATING REVENUES (000 s)[1]	$ 3,151,330	$ 3,156,524	$ 2,106,278	$ 1,618,602	$ 1,668,493

(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 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. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of September 30, 2007, these activities were limited in nature.

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.

Through January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of Atmos Energy Holdings, Inc., owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with other utility companies to own a limited partnership interest in Heritage Propane Partners, L.P. (Heritage), a publicly-traded marketer of propane through a nationwide retail distribution network. During fiscal 2004, we sold our interest in USP and Heritage. As a result of these transactions, we no longer have an interest in the propane business.

Table of Contents

Pipeline, Storage and Other Sales and Statistical Data

	Year Ended September 30				
	2007	2006	2005	2004	2003
OPERATING REVENUES (000 s)[1]	$ 33,400	$ 25,574	$ 15,639	$ 23,151	$ 23,151
PIPELINE TRANSPORTATION VOLUMES MMcf[1]	7,710	9,712	7,593	9,395	11,648
INVENTORY STORAGE BALANCE Bcf	2.0	2.6	1.8	2.3	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 under 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 doing business and to provide a reasonable return on invested capital.

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

Purchased gas mechanisms represent a common form of cost adjustment mechanism. Purchased gas adjustment mechanisms provide 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 hedges to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility company and its customers.

Current Ratemaking Strategy

Our current rate strategy focuses on seeking rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns due to weather-related variability, declining use per customer and energy conservation, also known as decoupling. Additionally, we are seeking to stratify rates to benefit low income households and to recover the gas cost portion of our bad debt expense.

Improving rate design is a long-term process. In the interim, we are addressing regulatory lag issues by directing discretionary capital spending to jurisdictions that permit us to recover our investment timely and file rate cases on a more frequent basis to minimize the regulatory lag to keep our actual returns more closely aligned with our allowed returns.

Table of Contents

Recent Ratemaking Activity

Approximately 97 percent of our natural gas distribution revenues in the fiscal years ended September 30, 2007, 2006 and 2005 were derived from sales at rates set by or subject to approval by local or state authorities. Of that amount, approximately 90 percent of our rate increases over the last three fiscal years have been obtained through rate making mechanisms that allow us to automatically refresh our rates without filing a formal rate case. Net annual revenue increases resulting from ratemaking activity totaling $40.1 million, $39.0 million and $6.3 million became effective in fiscal 2007, 2006 and 2005 as summarized below:

Rate Action	Increase (Decrease) to Revenue For the Year Ended September 30 2007	2006	2005
	(In thousands)		
GRIP filings	$ 25,624	$ 34,320	$ 1,802
Stable rate filings	11,628	3,326	4,525
Rate case filings	4,221	(191)	
Other rate activity	(1,359)	1,565	
	$ 40,114	$ 39,020	$ 6,327

Additionally, the following ratemaking efforts were initiated during fiscal 2007 but had not been completed as of September 30, 2007:

Division	Rate Action	Jurisdiction	Revenue Requested (In thousands)
Colorado-Kansas	Rate Case	Kansas	$ 4,978
Kentucky/Mid-States	Rate Case(1)	Tennessee	11,055
Mid-Tex	Rate Case	Texas	51,945
			$ 67,978

(1) The Tennessee rate case was settled in October 2007, resulting in an increase in annual revenue of $4.0 million and a $4.1 million reduction in depreciation expense.

Table of Contents

Our recent ratemaking activity is discussed in greater detail below.

GRIP Filings

As discussed above in the 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 years ended September 30, 2007, 2006 and 2005:

Division	Calendar Year	Incremental Net Utility Plant Investment (In thousands)	Additional Annual Revenue (In thousands)	Effective Date
2007 GRIP:				
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	
2006 GRIP:				
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	
2005 GRIP:				
Atmos Pipeline Texas	2003	$ 11,038	$ 1,802	4/1/05
Total 2005 GRIP		$ 11,038	$ 1,802	
GRIP pending approval:				
West Texas	2006	$ 7,022	$ 1,234	(2)
Total		$ 7,022	$ 1,234	

(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 in the table above.

(2) The West Texas 2006 GRIP filing is pending authorization from the RRC and the cities.

Table of Contents

Stable Rate Filings

As an instrument to reduce regulatory lag, a stable rate filing is a regulatory mechanism designed to allow us to refresh our rates on a periodic basis without filing a formal rate case. As discussed above in the Natural Gas Distribution Segment Overview, we currently have stable rate filings in our Louisiana and Mississippi Divisions. The following table summarizes our recent stable rate filings:

Division	Jurisdiction	Test Year Ended		Additional Annual Revenue (In thousands)	Effective Date
2007 Stable Rate Filings:					
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 Stable Rate Filings			$	11,628	
2006 Stable Rate Filings:					
Mississippi	Mississippi	6/30/06	$		11/1/06
Louisiana	LGS	12/31/03		3,326	2/1/06
Total 2006 Stable Rate Filings			$	3,326	
2005 Stable Rate Filings:					
Mississippi	Mississippi	9/30/04	$	4,300	2/2/05
Louisiana	LGS	12/31/02		225	10/1/04
Total 2005 Stable Rate Filings			$	4,525	

Rate Case Filings

A rate case is a formal request from Atmos Energy to a state s commission 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 as well as ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Increase (Decrease) in Annual	Effective

Division	State	Revenue (In thousands)	Date
2007 Rate Case Filings:			
Kentucky/Mid-States	Kentucky[1]	$ 5,500	8/1/07
Mid-Tex	Texas[2]	4,793	4/1/07
Kentucky/Mid-States	Missouri[3]		3/4/07
Kentucky/Mid-States	Tennessee	(6,072)	12/15/06
Total 2007 Rate Case Filings		$ 4,221	
2006 Rate Case Filings:			
Kentucky/Mid-States	Georgia	$ 409	11/22/05
Mississippi	Mississippi	(600)	10/1/05
Total 2006 Rate Case Filings		$ (191)	

See footnotes on the following page.

Table of Contents

(1) 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.

(2) 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 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.

(3) 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.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the years ended September 30, 2007, 2006 and 2005:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Revenue (In thousands)	Effective Date
2007 Other Rate Activity:				
Mid-Tex	Texas	GRIP Refund	$ (2,887)	4/1/07
Colorado-Kansas	Kansas	Ad Valorem Tax	1,528	1/1/07
2007 Other Rate Activity			$ (1,359)	
2006 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem Tax	$ 1,565	1/1/06
2006 Other Rate Activity			$ 1,565	

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 covers the prudence of gas purchases made from November 2003 through October 2006, which total approximately $2.7 billion. An agreed-upon procedural schedule has been filed with the RRC, which established a hearing schedule beginning in December 2007.

In August 2007, our Colorado-Kansas Division agreed with the Colorado Office of Consumer Counsel and the staff of the Colorado Public Utility Commission to issue a one-time credit to our Colorado customers of $1.1 million on customer bills in January 2008.

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 nor 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.

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 and agricultural 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 brokers in obtaining natural gas supplies for our customers.

Employees

At September 30, 2007, we had 4,653 employees, consisting of 4,526 employees in our regulated operations and 127 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, that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, 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

Table of Contents

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 has also periodically updated 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 such information free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors*

Our financial and operating results are subject to a number of factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other risks may prove to be important in the future. These factors include the following:

We are subject to regulation by each state in which we operate that affect our operations and financial results.

Our natural gas distribution and regulated transmission and storage businesses 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 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 . In addition, rate cases 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. Our debt and equity financings are also subject to approval by regulatory bodies in several states, which could limit our ability to take advantage of favorable market conditions.

Our business could also be affected by deregulation initiatives, including the development of unbundling initiatives in the natural gas industry. Unbundling is the separation of the provision and pricing of local distribution gas services into discrete components. It typically focuses on the separation of the distribution and gas supply components and the resulting opening of the regulated components of sales services to alternative unregulated suppliers of those services. Although we believe that our enhanced technology and distribution system infrastructures have positively positioned us, we cannot provide assurance that there would be no significant adverse effect on our business should unbundling or further deregulation of the natural gas distribution service business occur.

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

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 and storage 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 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 and storage 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 derivatives. 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. 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.

We are also subject to interest rate risk on our commercial paper 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, in the last three years, the Federal Reserve has taken actions that have generally resulted in increases in short-term interest rates. Future increases in interest rates could adversely affect our future financial results.

The concentration of our distribution, pipeline and storage operations in the State of Texas has increased the exposure of 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 are subject to greater impact than before from changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities.

Adverse weather conditions could affect our operations.

Beginning in 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, 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. In addition, 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.

The execution of our business plan could be affected by an inability to access capital markets.

We rely upon access to both short-term and long-term capital markets to satisfy our liquidity requirements. Adverse changes in the economy or these markets, the overall health of the industries in which we operate and changes to our credit ratings could limit access to these markets, increase our cost of capital or restrict the execution of our business plan.

Our long-term debt is currently rated as investment grade by Standard & Poor s Corporation (S&P), Moody s Investors Services, Inc. (Moody s) and Fitch Ratings, Ltd. (Fitch), the three credit rating agencies that rate our long-term debt securities. There can be no assurance that these rating agencies will maintain investment grade ratings for our long-term debt. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and reduce the borrowing capacity of our gas marketing affiliate. In addition, if our commercial paper ratings were lowered, it would increase the cost of commercial paper financing and could reduce or eliminate our ability to access the commercial paper markets. If we were unable to issue commercial paper at reasonable rates, we would likely borrow under our bank credit facilities to meet our working capital needs, which would likely increase the cost of our working capital financing.

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 influence future results.

Rapid increases in the price 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 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 of which is dependent on the interest rates at the time. 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 the 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.

Table of Contents

In the case of industrial customers, such as manufacturing plants and agricultural customers, 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 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. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

The cost of providing pension and postretirement health care benefits is subject to changes in pension fund values, changing demographics and 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 is subject to changes in the market value of our pension fund assets, 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, and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and interest rates and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

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. Such revised or new regulations could result in increased compliance costs or additional operating restrictions which could adversely affect our business, financial condition and results of operations.

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 financial position and results of operations 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 future financial results.

ITEM 1B. ***Unresolved Staff Comments***

Not applicable.

ITEM 2. ***Properties***

Distribution, transmission and related assets

At September 30, 2007, our natural gas distribution segment owned an aggregate of 76,362 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 6,290 miles of gas transmission and gathering lines and our pipeline, storage and other segment owned 73 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)
Natural Gas Distribution Segment				
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
Total	10,343,590	11,115,200	21,458,790	232,100
Regulated Transmission and Storage Segment Texas	39,128,475	13,128,025	52,256,500	1,235,000
Pipeline, Storage and Other Segment				
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
Total	3,931,483	3,595,973	7,527,456	127,000
Total	53,403,548	27,839,198	81,242,746	1,594,100

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

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)]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	4,237,243	108,232
	Kentucky/Mid-States Division	15,302,867	287,831
	Louisiana Division	2,689,695	163,692
	Mississippi Division	4,033,649	168,039
	West Texas Division	1,225,000	56,000
Total		27,488,454	783,794
Natural Gas Marketing Segment	Atmos Energy Marketing, LLC	11,874,654	271,167
Pipeline, Storage and Other Segment	Trans Louisiana Gas Pipeline, Inc.	1,050,000	60,000
Total Contracted Storage Capacity		40,413,108	1,114,961

(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 13 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 2007.

Table of Contents

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2007, 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	60	10	Chairman, President and Chief Executive Officer
Kim R. Cocklin	56	1	Senior Vice President, Utility Operations
Louis P. Gregory	52	7	Senior Vice President and General Counsel
Mark H. Johnson	48	6	Senior Vice President, Nonutility Operations and President, Atmos Energy Marketing, LLC
Wynn D. McGregor	54	19	Senior Vice President, Human Resources
John P. Reddy	54	9	Senior Vice President and Chief Financial Officer

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997.

Kim R. Cocklin joined the Company in June 2006 as Senior Vice President, Utility Operations. 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. Prior to joining Piedmont, Mr. Cocklin was with Williams Gas Pipeline from 1995 to January 2003, where he served in various capacities, including serving as Vice President for rates, regulatory and business development for all of the Williams Gas pipelines from 2001 to January 2003.

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

Mark H. Johnson was named Senior Vice President, Nonutility 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. Mr. Johnson joined Atmos Energy Marketing s predecessor, Woodward Marketing, L.L.C., in 1992 as Vice President of Marketing and Operations and was later promoted to Senior Vice President of Marketing for the Midwest and Gulf Coast through September 2003.

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.

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 2007 and 2006 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:

	2007			2006		
	High	**Low**	**Dividends Paid**	**High**	**Low**	**Dividends Paid**
Quarter ended:						
December 31	$ 33.01	$ 28.45	$ .320	$ 28.36	$ 25.79	$ .315
March 31	33.00	30.63	.320	27.00	26.10	.315
June 30	33.11	29.38	.320	27.91	26.00	.315
September 30	30.66	26.47	.320	29.11	27.96	.315
			$ 1.28			$ 1.26

Dividends are payable at the discretion of our Board of Directors out of legally available funds and are also subject to restriction under the terms of our First Mortgage Bond agreement. See Note 6 to the consolidated financial statements. 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, 2007 was 22,912. 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 2007 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 a customized peer company group, the Comparison Company Index, which is comprised of utility 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, 2002 in our common stock, the S&P 500 Index and in the common stock of the companies in the Comparison Company Index, 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 Index

	Cumulative Total Return					
	9/30/02	**9/30/03**	**9/30/04**	**9/30/05**	**9/30/06**	**9/30/07**
Atmos Energy Corporation	100.00	117.25	129.58	152.04	160.99	166.39
S&P 500 Index	100.00	124.40	141.65	159.01	176.17	205.13
Comparison Company Index	100.00	120.89	146.79	206.79	202.30	239.05

The 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., Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Questar Corporation, Vectren Corporation and WGL Holdings, Inc. KeySpan Corporation is no longer included in the index since it was acquired by National Grid plc in August 2007; Peoples Energy Corporation is no longer included in the index since it was acquired by WPS Resources, Inc. to form Integrys Energy Group, Inc. in February 2007.

Table of Contents

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2007.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)		Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders:				
Long-Term Incentive Plan	920,841	$	22.54	2,730,192
Total equity compensation plans approved by security holders	920,841		22.54	2,730,192
Equity compensation plans not approved by security holders				
Total	920,841	$	22.54	2,730,192

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.

	Year Ended September 30				
	2007[1]	2006[1]	2005[2]	2004[3]	2003[4]
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$ 5,898,431	$ 6,152,363	$ 4,961,873	$ 2,920,037	$ 2,799,916
Gross profit	1,250,082	1,216,570	1,117,637	562,191	534,976
Operating expenses[1]	851,446	833,954	768,982	368,496	347,136
Operating income	398,636	382,616	348,655	193,695	187,840
Miscellaneous income[3]	9,184	881	2,021	9,507	2,191
Interest charges	145,236	146,607	132,658	65,437	63,660
Income before income taxes and cumulative effect of accounting change	262,584	236,890	218,018	137,765	126,371
Cumulative effect of accounting change, net income tax benefit					(7,773)
Income tax expense	94,092	89,153	82,233	51,538	46,910
Net income	$ 168,492	$ 147,737	$ 135,785	$ 86,227	$ 71,688
Weighted average diluted shares outstanding	87,745	81,390	79,012	54,416	46,496
Diluted net income per share	$ 1.92	$ 1.82	$ 1.72	$ 1.58	$ 1.54
Cash flows from operations	547,095	311,449	386,944	270,734	49,541
Cash dividends paid per share	$ 1.28	$ 1.26	$ 1.24	$ 1.22	$ 1.20
Total natural gas distribution throughput (MMcf)	427,869	393,995	411,134	246,033	247,965
Total regulated transmission and storage transportation volumes (MMcf)	505,493	410,505	373,879		
Total natural gas marketing sales volumes (MMcf)	370,668	283,962	238,097	222,572	225,961
Financial Condition					
Net property, plant and equipment[5]	$ 3,836,836	$ 3,629,156	$ 3,374,367	$ 1,722,521	$ 1,624,394
Working capital[5]	149,217	(1,616)	151,675	283,310	16,248
Total assets[5][6]	5,896,917	5,719,547	5,653,527	2,912,627	2,625,495
Short-term debt, inclusive of current maturities of long-term debt	154,430	385,602	148,073	5,908	127,940
Capitalization:					
Shareholders equity	1,965,754	1,648,098	1,602,422	1,133,459	857,517
	2,126,315	2,180,362	2,183,104	861,311	862,500

Long-term debt (excluding current maturities)					
Total capitalization	4,092,069	3,828,460	3,785,526	1,994,770	1,720,017
Capital expenditures	392,435	425,324	333,183	190,285	159,439
Financial Ratios					
Capitalization ratio(6)	46.3%	39.1%	40.7%	56.7%	46.4%
Return on average shareholders equity(7)	8.8%	8.9%	9.0%	9.1%	9.9%

See footnotes on the following page.

(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) Financial results for fiscal 2003 include the results of MVG from December 3, 2002, the date of acquisition.

(5) Beginning in 2004, we reclassified our regulatory cost of removal obligation from accumulated depreciation to a liability. These reclassifications did not impact our financial position, results of operations or cash flows as of and for the year ended September 30, 2003.

(6) 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. Beginning in 2004 we reclassified our original issue discount costs from deferred charges and other assets to long-term debt. This reclassification did not materially impact our capitalization or our capitalization ratio as of September 30, 2003.

(7) 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.

The following table presents a condensed income statement by segment for the year ended September 30, 2007.

	Year Ended September 30, 2007 (In thousands)					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
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	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

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 , se
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: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in one state; adverse weather conditions; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; the capital-intensive nature of our distribution business, increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the impact of environmental regulations on our business; the inherent hazards and risks involved in operating our distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, especially 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 accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the 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 cycle 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. Revenue is recognized in our regulated transmission and storage segment as the services are provided.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities and 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 expense, 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.

Energy trading contracts resulting in the delivery of a commodity in which we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts are included as a component of natural gas marketing revenues.

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

Allowance for doubtful accounts We record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect based upon our collections experiences and our assessment of our customers inability or reluctance to pay. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Derivatives and hedging activities Our natural gas distribution segment uses a combination of physical storage and financial derivatives to partially insulate our natural gas distribution customers against gas price volatility during the winter heating season. These financial derivatives have not been designated as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Accordingly, they are recorded at fair value. However, because the costs associated with and the gains and losses arising from these financial derivatives are included in our purchased gas adjustment mechanisms, changes in the fair value of these financial derivatives are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas costs when the related costs are recovered through our rates 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 derivatives.

Our natural gas marketing and pipeline, storage and other segments are exposed to commodity price risk associated with our natural gas inventories, and, in our natural gas marketing segment, on our fixed-price contracts. We manage this risk through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. 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. The use of these contracts is subject to our risk management policies, which are monitored for compliance daily.

We have designated the natural gas inventory held by Atmos Energy Marketing and Atmos Pipeline and Storage, LLC 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 derivatives 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 the period of change. The difference in the spot price used to value our physical inventory (Gas Daily) and the forward price used to value the related fair-value hedges (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

We recognize revenue and the associated carrying value of the inventory (inclusive of storage costs) as purchased gas costs in our consolidated statement of income when we sell the gas and deliver it out of the storage facility. 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 our fixed-price forward contracts as normal purchases and sales and have designated the associated derivative contracts as cash flow hedges of anticipated transactions. Accordingly, unrealized gains and losses on these open derivative contracts 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.

Additionally, our natural gas marketing segment utilizes 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. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges pursuant to SFAS 133. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue.

In addition to mitigating commodity price risk, we periodically manage our exposure to interest rate changes by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We have designated each of our previously executed 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 are recorded as a component of accumulated other comprehensive income. The realized gain or loss recognized upon settlement of the Treasury lock agreement is initially recorded as a component of accumulated other comprehensive income and is recognized as a component of interest expense over the life of the related financing arrangement.

The fair value of all of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from 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 derivatives. We believe the market prices and models used to value these derivatives 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.

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. 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. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. 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

Table of Contents

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 our 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 cost over a period of approximately ten to twelve years.

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 cost ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement cost by approximately $0.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement cost 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 year and lower operating revenues and either lower net income or net losses during the period from April through September of each 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 63 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 this industry impacts the levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances we report at various time of the fiscal year.

Table of Contents

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2007, 2006 and 2005.

	For the Year Ended September 30 2007	2006	2005
	(In thousands, except per share data)		
Operating revenues	$ 5,898,431	$ 6,152,363	$ 4,961,873
Gross profit	1,250,082	1,216,570	1,117,637
Operating expenses	851,446	833,954	768,982
Operating income	398,636	382,616	348,655
Miscellaneous income	9,184	881	2,021
Interest charges	145,236	146,607	132,658
Income before income taxes	262,584	236,890	218,018
Income tax expense	94,092	89,153	82,233
Net income	$ 168,492	$ 147,737	$ 135,785
Earnings per diluted share	$ 1.92	$ 1.82	$ 1.72

Historically, our regulated operations arising from our natural gas distribution operations and, beginning in fiscal 2005, from our Atmos Pipeline Texas division, contributed 65 to 85 percent of our consolidated net income. However, in recent years, this contribution has declined due to the growth of our nonregulated natural gas marketing and pipeline and storage businesses coupled with lower natural gas distribution income. Regulated operations contributed 64 percent, 54 percent and 80 percent to our consolidated net income for fiscal years 2007, 2006 and 2005. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Year Ended September 30 2007	2006	2005
	(In thousands)		
Natural gas distribution segment	$ 73,283	$ 53,002	$ 81,117
Regulated transmission and storage segment	34,590	26,547	27,582
Natural gas marketing segment	45,769	58,566	23,404
Pipeline, storage and other segment	14,850	9,622	3,682
Net income	$ 168,492	$ 147,737	$ 135,785

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

	For the Year Ended September 30 2007	2006	2005
	(In thousands, except per share data)		

Regulated operations	$ 107,873	$ 79,549	$ 108,699
Nonregulated operations	60,619	68,188	27,086
Consolidated net income	$ 168,492	$ 147,737	$ 135,785
Diluted EPS from regulated operations	$ 1.23	$ 0.98	$ 1.38
Diluted EPS from nonregulated operations	0.69	0.84	0.34
Consolidated diluted EPS	$ 1.92	$ 1.82	$ 1.72

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-

Table of Contents

Tex and Louisiana Divisions coupled with increased throughput and incremental gross profit margins from our North Side Loop 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.

The nine percent year-over-year increase in net income during fiscal 2006 primarily reflects strong results in our nonregulated operations, partially offset by a decrease in our regulated operations. The net income from our nonregulated operations reflect the favorable impact of a volatile natural gas market, which provided increased opportunities to maximize delivered gas margins. Our nonregulated results were also favorably impacted by recording unrealized gains during fiscal 2006 compared to recording unrealized losses in fiscal 2005. The decrease in net income from our regulated operations primarily reflects the adverse effects on our natural gas distribution segment of weather (adjusted for WNA) that was 13 percent warmer than normal, the adverse effect of Hurricane Katrina on our Louisiana Division and a non-recurring, noncash charge to impair our West Texas Division irrigation assets.

Other key financial and significant events for the year ended September 30, 2007 include the following:

In December 2006, we filed a $900 million shelf registration statement with the SEC that replaced our previously existing shelf registration statement. Upon completion of the filing of this registration statement, we received net proceeds of approximately $192 million through the issuance of approximately 6.3 million shares of common stock. The net proceeds received were used to repay a portion of our then-existing short-term debt balance.

In June 2007, we received net proceeds of approximately $247 million from the issuance of senior notes. The net proceeds received, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes, which were redeemed on July 15, 2007.

Our total-debt-to-capitalization ratio at September 30, 2007 was 53.7 percent compared with 60.9 percent at September 30, 2006, primarily reflecting the $50 million reduction in long-term debt and lower short-term debt balances as of September 30, 2007.

For the year ended September 30, 2007, we generated $547.1 million in operating cash flow compared with $311.4 million for the year ended September 30, 2006, primarily reflecting the favorable impact of increased earnings, increased sales volumes attributable to colder weather during the period and lower natural gas prices.

Capital expenditures decreased to $392.4 million during the year ended September 30, 2007 from $425.3 million in the prior year. The decrease primarily reflects the absence of capital spending for the North Side Loop and other compression projects completed in fiscal 2006.

In March 2007, the Texas Railroad Commission issued an order in our Mid-Tex Division s rate case, which prospectively increased annual revenues by approximately $4.8 million and established a permanent WNA based upon a 10-year average effective for the months of November through April. However, the ruling also reduced the Mid-Tex Division s total return to 7.903 percent from 8.258 percent and required a $2.9 million refund, inclusive of interest, of amounts collected from our calendar 2003 2005 GRIP filings.

Table of Contents

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

Year ended September 30, 2007 compared with year ended September 30, 2006

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.

One example of our recent ratemaking initiatives involves the substantial separation of the recovery of our margins from seasonal weather patterns. Prior to fiscal 2007, seasonal weather patterns significantly impacted our natural gas distribution results. The rate design in our two most weather-sensitive jurisdictions, the Louisiana and Mid-Tex divisions, which represent approximately 60 percent of our natural gas distribution residential and commercial meters, provided for limited weather protection. During fiscal 2006, we received WNA in these jurisdictions, beginning with the 2006-2007 winter heating season. WNA substantially offsets the effects of weather that is above or below normal by allowing us to increase the base rate portion of customers bills when weather is warmer than normal and to decrease the base rate when weather is colder than normal. Accordingly, gross profit margin in our service areas covered by WNA should be based substantially on the amount of gross profit that would result from normal weather, despite actual weather conditions that may be either warmer or colder than normal. After receiving WNA in our Louisiana and Mid-Tex divisions, we have weather protection for over 90 percent of our residential and commercial meters, which should substantially reduce the volatility in this segment s operating results.

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 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.

Table of Contents

Review of Financial and Operating Results

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

	For the Year Ended September 30 2007	2006
	(In thousands, unless otherwise noted)	
Gross profit	$ 952,684	$ 925,057
Operating expenses	731,497	723,163
Operating income	221,187	201,894
Miscellaneous income	8,945	9,506
Interest charges	121,626	126,489
Income before income taxes	108,506	84,911
Income tax expense	35,223	31,909
Net income	$ 73,283	$ 53,002
Natural gas distribution sales volumes MMcf	297,327	272,033
Natural gas distribution transportation volumes MMcf	130,542	121,962
Total natural gas distribution throughput MMcf	427,869	393,995
Heating degree days		
Actual (weighted average)	2,879	2,527
Percent of normal	100%	87%
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.45	$ 0.50
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 8.09	$ 10.02

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	
	Operating Income (Loss)	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 22,392	104%	$ 22,524	99%

Kentucky/Mid-States	42,161	97%	49,893	98%
Louisiana	44,193	105%	27,772	78%
Mid-Tex	68,574	100%	71,703	72%
Mississippi	23,225	101%	23,276	102%
West Texas	21,036	99%	2,215	100%
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 and commercial customers, which 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 $1.7 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 $3.7 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 year ended September 30, 2007 from $723.2 million for the 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 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 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 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 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.

Table of Contents

Interest charges

Interest charges allocated to the natural gas distribution segment for the year ended September 30, 2007 decreased to $121.6 million from $126.5 million for the 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

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. 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 years ended September 30, 2007 and 2006 are presented below.

	For the Year Ended September 30	
	2007	**2006**
	(In thousands, unless otherwise noted)	
Mid-Tex transportation	$ 77,090	$ 69,925
Third-party transportation	65,158	56,813
Storage and park and lend services	9,374	8,047
Other	11,607	6,348
Gross profit	163,229	141,133
Operating expenses	83,399	77,807
Operating income	79,830	63,326
Miscellaneous income (expense)	2,105	(153)
Interest charges	27,917	22,787
Income before income taxes	54,018	40,386
Income tax expense	19,428	13,839
Net income	$ 34,590	$ 26,547

Pipeline transportation volumes	MMcf	505,493	410,505

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 year ended September 30, 2007 from $77.8 million for the 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 year ended September 30, 2007 increased to $27.9 million from $22.8 million for the 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.

Natural Gas Marketing Segment

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. 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 derivative products. As a result, revenues and gross profit from this segment 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 perform.

To optimize the storage and transportation capacity we own or control, we 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. Additionally, we engage 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 contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivative contracts, we seek to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM continually manages its net physical position to enhance the future economic profit it captured when an original transaction was executed. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective.

The natural gas inventory used in our natural gas marketing storage activities is marked to market at the end of each month based upon the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. We use derivatives, designated as fair value hedges, to hedge this natural gas inventory. These derivatives 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 changes between 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 the unrealized margins reported as a part of our storage activities until the underlying physical gas is cycled and the related financial derivatives are settled.

AEM also uses derivative instruments to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original physical inventory hedge and to insulate and protect the economic value within its storage and marketing activities. Changes in fair value associated with these financial

Table of Contents

instruments are recognized as unrealized gains and losses within AEM s storage and marketing activities until they are settled.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the years ended September 30, 2007 and 2006 are presented below. Gross profit margin for our natural gas marketing segment consists primarily of margins earned from the delivery of gas and related services requested by our customers; and asset optimization activities, which are derived from the utilization of our managed proprietary and 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 the derivative contracts used by our natural gas marketing segment 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 contingent upon the levels of our net physical position at the end of the reporting period.

	For the Year Ended September 30	
	2007	**2006**
	(In thousands, unless otherwise noted)	
Delivered gas	$ 57,054	$ 87,236
Asset optimization	28,827	26,225
Unrealized margins	18,430	17,166
Gross profit	104,311	130,627
Operating expenses	29,271	28,392
Operating income	75,040	102,235
Miscellaneous income	6,434	2,598
Interest charges	5,767	8,510
Income before income taxes	75,707	96,323
Income tax expense	29,938	37,757
Net income	$ 45,769	$ 58,566
Natural gas marketing sales volumes MMcf	370,668	283,962
Net physical position (Bcf)	12.3	14.5

The $26.3 million decrease in our natural gas marketing segment s gross profit primarily reflects lower delivered gas margins, partially offset by higher asset optimization margins.

Delivered gas margins decreased $30.2 million compared with the prior-year period. 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 current fiscal year compared with the prior year.

Asset optimization margins increased $2.6 million compared with the prior-year period. The increase reflects greater cycled storage volumes during the current-year period, partially offset by an increase in storage fees and park and loan fees which reduced the arbitrage spreads available.

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 year ended September 30, 2007 from $28.4 million for the 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 year ended September 30, 2007 from $2.6 million for the 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 interest income earned on our margin account associated with increased margin requirements during the current year.

Interest charges

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

Economic Gross Profit

AEM monitors the impacts of its asset optimization efforts by estimating the gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented to provide a measure of the potential gross profit from asset optimization that could occur in future periods if AEM s optimization efforts are executed as planned. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents AEM s economic gross profit and its potential gross profit for the last three fiscal years.

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, 2007	12.3	$ 40.8	$ 10.8	$ 30.0
September 30, 2006	14.5	$ 60.0	$ (16.0)	$ 76.0
September 30, 2005	6.9	$ 13.1	$ (14.8)	$ 27.9

As of September 30, 2007, based upon AEM s derivatives position and inventory withdrawal schedule, the economic gross profit was $40.8 million. This amount is reduced by $10.8 million of net unrealized gains recorded in the financial statements as of September 30, 2007 that will reverse when the inventory is withdrawn and the accompanying financial derivatives are settled. Therefore, the potential gross profit was $30.0 million. This potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses and increased income taxes to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled 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, 2007 will be fully realized in the future or in what time period. 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.

Table of Contents

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 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. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of September 30, 2007, these activities were limited in nature.

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, these activities were moved to our shared services function included in our natural gas distribution segment. 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 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.

Review of Financial and Operating Results

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

	For the Year Ended September 30	
	2007	**2006**
	(In thousands, unless otherwise noted)	
Storage and transportation services	$ 15,968	$ 11,841
Asset optimization	10,751	3,387
Other	3,792	5,916
Unrealized margins	2,097	3,350
Gross profit	32,608	24,494
Operating expenses	10,373	9,570
Operating income	22,235	14,924
Miscellaneous income	8,173	6,858
Interest charges	6,055	6,512

Income before income taxes		24,353		15,270
Income tax expense		9,503		5,648
Net income	$	14,850	$	9,622
Pipeline transportation volumes MMcf		4,150		5,439

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 year ended September 30, 2007 from $9.6 million for the 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 year ended September 30, 2007 from $6.9 million for the 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 year ended September 30, 2007 decreased to $6.1 million from $6.5 million for the year ended September 30, 2006. The decrease was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Year ended September 30, 2006 compared with year ended September 30, 2005

Natural Gas Distribution Segment

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2006 and 2005 are presented below.

	For the Year Ended September 30	
	2006	2005
	(In thousands, unless otherwise noted)	
Gross profit	$ 925,057	$ 907,366
Operating expenses	723,163	671,001
Operating income	201,894	236,365
Miscellaneous income	9,506	6,776
Interest charges	126,489	112,382
Income before income taxes	84,911	130,759
Income tax expense	31,909	49,642
Net income	$ 53,002	$ 81,117
Natural gas distribution sales volumes MMcf	272,033	296,283
Natural gas distribution transportation volumes MMcf	121,962	114,851
Total natural gas distribution throughput MMcf	393,995	411,134

Heating degree days		
Actual (weighted average)	2,527	2,587
Percent of normal	87%	89%
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.50	$ 0.51
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 10.02	$ 7.41

47

Table of Contents

The following table shows our operating income by natural gas distribution division for the fiscal years ended September 30, 2006 and 2005. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	2006		2005	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 22,524	99%	$ 25,157	99%
Kentucky/Mid-States	49,893	98%	54,344	96%
Louisiana	27,772	78%	24,819	78%
Mid-Tex	71,703	72%	84,965	80%
Mississippi	23,276	102%	19,045	96%
West Texas	2,215	100%	27,520	99%
Other	4,511		515	
Total	$ 201,894	87%	$ 236,365	89%

(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.

Natural gas distribution gross profit increased to $925.1 million for the year ended September 30, 2006 from $907.4 million for the year ended September 30, 2005. Total throughput for our natural gas distribution business was 394.0 Bcf during the current year compared to 411.1 Bcf in the prior year.

The increase in natural gas distribution gross profit, despite lower throughput, primarily reflects higher franchise fees and state gross receipts taxes, which are paid by customers and have no permanent effect on net income. Additionally, margins increased approximately $14.0 million due to rate increases received from our fiscal 2005 and fiscal 2004 GRIP filings and the recognition of $3.3 million that had been previously deferred in Louisiana following the LPSC s ratification of our agreement in May 2006. These increases were partially offset by approximately $22.9 million due to the impact of significantly warmer than normal weather, particularly in our Mid-Tex and Louisiana divisions. For the year ended September 30, 2006, weather was 13 percent warmer than normal, as adjusted for jurisdictions with weather-normalized operations and two percent warmer than the prior year. In the Mid-Tex and Louisiana Divisions, which did not have weather-normalized rates during the 2005-2006 winter heating season, weather was 28 percent and 22 percent warmer than normal.

Additionally, natural gas distribution gross profit decreased approximately $2.9 million compared with the prior year in the Louisiana Division due to the impact of Hurricane Katrina. Service has been restored in some areas affected by the storm; however, it is likely that service will not be restored to all of the affected service areas. As more fully described under Ratemaking Activity, we implemented new rates in September 2006 that reflect the impact of Hurricane Katrina.

Operating expenses increased to $723.2 million for the year ended September 30, 2006 from $671.0 million for the year ended September 30, 2005. The increase reflects a $13.3 million increase in taxes, other than income, primarily related to franchise fees and state gross receipts taxes, both of which are calculated as a percentage of revenue, and are paid by our customers as a component of their monthly bills. Although these amounts are included as a component of revenue in accordance with our tariffs, timing differences between when these amounts are billed to our customers and when we recognize the associated expense may affect net income favorably or unfavorably on a temporary basis. However, there is no permanent effect on net income.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $7.8 million primarily due to higher employee costs associated with increased headcount to fill positions that were previously outsourced to a third party, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Increased line locate, telecommunication and facilities costs also contributed to the overall increase. These increases were partially offset by a reduction in third-party costs for outsourced administrative and meter reading functions that were in-sourced during fiscal 2006. Operation and maintenance expense for the year ended September 30, 2006 was also favorably impacted by the absence of $2.1 million of merger and integration cost amortization associated with the merger of United Cities Gas Company in July 1997, as these costs were fully amortized by December 2004.

The provision for doubtful accounts increased $3.1 million to $20.6 million for the year ended September 30, 2006, compared with $17.5 million in the prior year. The increase was primarily attributable to increased collection risk associated with higher natural gas prices. In the natural gas distribution segment, the average cost of natural gas for the year ended September 30, 2006 was $10.02 per Mcf, compared with $7.41 per Mcf for the year ended September 30, 2005.

Additionally, during the first quarter of fiscal 2006, the MPSC, in connection with the modification of our rate design, decided to allow the recovery of $2.8 million in deferred costs, which it had originally disallowed in its September 2004 decision. This charge was originally recorded in fiscal 2004. This ruling decreased our depreciation expense during the year ended September 30, 2006. This decrease was offset by increased depreciation expense associated with the placement of various capital projects into service during the fiscal year.

Operating expenses were also impacted by a $22.9 million noncash charge to impair our West Texas Division s irrigation assets. During the fiscal 2006 fourth quarter, 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, the entire net book value was written off. We will continue to operate these assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets. We are currently evaluating an opportunity to sell these assets in the first quarter of fiscal 2008. We do not expect the outcome of this potential transaction to materially affect our results of operations.

As a result of the aforementioned factors, our natural gas distribution segment operating income for the year ended September 30, 2006 decreased to $201.9 million from $236.4 million for the year ended September 30, 2005.

Miscellaneous income

Miscellaneous income for the year ended September 30, 2006 was $9.5 million compared to miscellaneous income of $6.8 million for the year ended September 30, 2005. This increase was primarily attributable to increased interest income on intercompany borrowings to our natural gas marketing segment to fund its working capital needs. This increase was partially offset by a $3.3 million charge recorded during the fiscal 2006 second quarter associated with an adverse ruling in Tennessee related to the calculation of a performance-based rate mechanism associated with gas purchases.

Interest charges

Interest charges allocated to the natural gas distribution segment for the year ended September 30, 2006 increased to $126.5 million from $112.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding short-term debt balances to fund natural gas purchases at significantly higher prices coupled with an approximate 200 basis point increase in the interest rate on our $300 million unsecured floating rate Senior Notes due 2007 due to an increase in the three-month LIBOR rate. These increases were partially offset by $4.8 million of interest savings arising from the early payoff of $72.5 million of our First Mortgage Bonds in June 2005.

Table of Contents

Regulated Transmission and Storage Segment

Financial and operational highlights for our regulated transmission and storage segment for the years ended September 30, 2006 and 2005 are presented below.

	For the Year Ended September 30	
	2006	2005
	(In thousands, unless otherwise noted)	
Mid-Tex transportation	$ 69,925	$ 70,089
Third-party transportation	56,813	44,348
Storage and park and lend services	8,047	4,235
Other	6,348	19,362
Gross profit	141,133	138,034
Operating expenses	77,807	72,194
Operating income	63,326	65,840
Miscellaneous income (expense)	(153)	150
Interest charges	22,787	23,344
Income before income taxes	40,386	42,646
Income tax expense	13,839	15,064
Net income	$ 26,547	$ 27,582
Pipeline transportation volumes MMcf	410,505	373,879

Gross profit increased to $141.1 million for the year ended September 30, 2006 from $138.0 million for the year ended September 30, 2005. Total pipeline transportation volumes were 581.3 Bcf during the year ended September 30, 2006, compared with 554.5 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 410.5 Bcf during the current year compared with 373.9 Bcf in the prior year.

The increase in gross profit was primarily attributable to increased third-party throughput and ancillary service margins. The increase in third-party transportation margins was primarily attributable to increases in the electric-generation market due to the warmer than normal temperatures during the summer of 2006, increased demand for through-system transportation services due to a widening of pricing differentials between the pipeline s hubs and the impact of Atmos Pipeline Texas North Side Loop and other compression projects that were placed into service in June 2006. Storage and parking and lending services on Atmos Pipeline Texas also increased during fiscal 2006 as a result of the widening of pricing differentials between the pipeline s hubs, which increased the attractiveness of storing gas on the pipeline and our ability to obtain improved margins for these services. The increases on Atmos Pipeline Texas system were partially offset by a decrease in margins earned from intercompany transportation services to our Mid-Tex Division due to the significantly warmer than normal weather experienced during fiscal 2006. Additionally, these increases were partially offset by the absence of inventory sales of $3.0 million realized in the prior year.

Operating expenses increased to $77.8 million for the year ended September 30, 2006 from $72.2 million for the year ended September 30, 2005 due to higher employee benefit costs associated with an increase in headcount, increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs, higher facilities costs and higher pipeline integrity costs.

As a result of the aforementioned factors, our regulated transmission and storage segment operating income for the year ended September 30, 2006 decreased to $63.3 million from $65.8 million for the year ended September 30, 2005.

Table of Contents

Natural Gas Marketing Segment

Financial and operational highlights for our natural gas marketing segment for the years ended September 30, 2006 and 2005 are presented below.

	For the Year Ended September 30	
	2006	2005
	(In thousands, unless otherwise noted)	
Delivered gas	$ 87,236	$ 59,971
Asset optimization	26,225	28,008
Unrealized margins	17,166	(26,006)
Gross profit	130,627	61,973
Operating expenses	28,392	20,988
Operating income	102,235	40,985
Miscellaneous income	2,598	771
Interest charges	8,510	3,405
Income before income taxes	96,323	38,351
Income tax expense	37,757	14,947
Net income	$ 58,566	$ 23,404
Natural gas marketing sales volumes MMcf	283,962	238,097
Net physical position (Bcf)	14.5	6.9

The $68.7 million increase in our natural gas marketing segment s gross profit reflects increased delivered gas margins and increased unrealized margins partially offset by a decrease in asset optimization margins.

Delivered gas margins increased $27.3 million during fiscal 2006 as a result of increased sales volumes resulting from focusing our marketing efforts on higher margin opportunities partially offset by warmer-than-normal weather across our market areas. The increase in gas delivery margins also reflected our ability to successfully capture increased per unit margins in certain market areas that experienced higher market volatility.

Asset optimization margins decreased $1.8 million primarily due to the realization of less favorable arbitrage spreads during the current year period compared with the prior year, coupled with increased storage fees.

The favorable unrealized margin variance primarily was due to a favorable movement during the year ended September 30, 2006 in the forward natural gas prices associated with financial derivatives used in our gas delivery activities, a narrowing of the physical/forward spreads during fiscal 2006 and positive basis ineffectiveness on our financial derivatives. These results were magnified by a 7.6 Bcf increase in our net physical position at September 30, 2006 compared to the prior year.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $28.4 million for the year ended September 30, 2006 from $21.0 million for the year ended September 30, 2005. The increase in operating expense primarily was attributable to an increase in personnel costs due to increased headcount and an increase in regulatory compliance costs.

The improved gross profit margin partially offset by higher operating expenses resulted in an increase in our natural gas marketing segment operating income to $102.2 million for the year ended September 30, 2006 compared with operating income of $41.0 million for the year ended September 30, 2005.

Table of Contents

Interest charges

Interest charges allocated to the natural gas marketing segment for the year ended September 30, 2006 increased to $8.5 million from $3.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding debt balances to fund natural gas purchases at significantly higher prices.

Pipeline, Storage and Other Segment

Financial and operational highlights for our pipeline, storage and other segment for the years ended September 30, 2006 and 2005 are presented below.

	For the Year Ended September 30	
	2006	2005
	(In thousands, unless otherwise noted)	
Storage and transportation services	$ 11,841	$ 11,539
Asset optimization	3,387	1,613
Other	5,916	5,324
Unrealized margins	3,350	(4,730)
Gross profit	24,494	13,746
Operating expenses	9,570	8,482
Operating income	14,924	5,264
Miscellaneous income	6,858	4,455
Interest charges	6,512	3,457
Income before income taxes	15,270	6,262
Income tax expense	5,648	2,580
Net income	$ 9,622	$ 3,682
Pipeline transportation volumes MMcf	5,439	5,580

Gross profit increased to $24.5 million for the year ended September 30, 2006 from $13.7 million for the year ended September 30, 2005. The increase in gross profit was primarily attributable to increased unrealized gains recorded during fiscal 2006 as favorable movements in the forward natural gas prices used to value the financial hedges designated against the physical inventory underlying these contracts resulted in an unrealized gain compared with an unrealized loss in the prior year. Additionally, APS recorded increased margins from its asset optimization activities due to its ability to capture more favorable arbitrage spreads.

Operating expenses increased to $9.6 million for the year ended September 30, 2006 from $8.5 million for the year ended September 30, 2005 due to higher employee and other administrative costs.

As a result of the aforementioned factors, our pipeline, storage and other segment operating income for the year ended September 30, 2006 increased to $14.9 million from $5.3 million for the year ended September 30, 2005.

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 through our existing shelf registration statement to fund our liquidity needs.

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 are primarily attributable to working capital changes within our natural gas distribution segment resulting from the impact of the price of natural gas and the timing of customer collections, payments for natural gas purchases, deferred gas cost recoveries and weather.

For the year ended September 30, 2007, we generated operating cash flow of $547.1 million compared with $311.4 million in fiscal 2006 and $386.9 million in fiscal 2005. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

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 cost 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 current year.

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 a margin account and therefore favorably affected operating cash flow by $126.3 million.

Year ended September 30, 2005

Fiscal 2005 operating cash flows reflect the effects of a $49.6 million increase in net income and effective working capital management partially offset by higher natural gas prices. Working capital management efforts, which affected the timing of payments for accounts payable and other accrued liabilities, favorably affected operating cash flow by $354.1 million. However, these efforts were partially offset by reduced cash flow generated from accounts receivable changes by $168.9 million, primarily attributable to higher natural gas prices, and an increase in our natural gas inventories attributable to a 13 percent year-over-year increase in natural gas prices coupled with increased natural gas inventory levels, which reduced operating cash flow by $81.8 million. Operating cash flow was also adversely impacted by unfavorable movements in the indices used to value our natural gas marketing segment risk management assets and liabilities, which resulted in a net liability for the segment. Accordingly, under the terms of the associated derivative contracts, we were required to deposit $81.0 million into a margin account.

Cash flows from investing activities

In recent 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 return on our investment timely. 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 year ended September 30, 2007, we incurred $392.4 million for capital expenditures compared with $425.3 million for the year ended September 30, 2006 and $333.2 million for the year ended September 30, 2005. 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. Our cash used for investing activities for the year ended September 30, 2005 reflects the $1.9 billion cash paid for the TXU Gas acquisition, including related transaction costs and expenses.

Cash flows from financing activities

For the year ended September 30, 2007, our financing activities used $159.3 million in cash compared with $155.3 million and $1.7 billion provided for the years ended September 30, 2006 and 2005. Our significant financing activities for the years ended September 30, 2007, 2006 and 2005 are summarized as follows:

In December 2006, we raised net proceeds of approximately $192 million from the sale of approximately 6.3 million shares of common stock, including the underwriters exercise of their overallotment option of 0.8 million shares, under a shelf registration statement filed with the SEC in December 2006. The net proceeds from this issuance were used to reduce our then-existing short-term debt balance.

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.

During the years ended September 30, 2006 and 2005, we increased our borrowings under our short-term facilities by $237.6 million and $144.8 million whereas during the year ended September 30, 2007, we repaid a net $213.2 million under our short-term facilities. Net borrowings under our short-term facilities during fiscal 2006 and 2005 reflect the impact of seasonal natural gas purchases and the effect of higher natural gas prices.

We repaid $303.2 million of long-term debt during the year ended September 30, 2007, compared with $3.3 million during the year ended September 30, 2006 and $103.4 million during the year ended September 30, 2005. Fiscal 2005 payments reflected the repayment of $72.5 million of our First Mortgage Bonds. In connection with this repayment we paid a $25.0 million make-whole premium in accordance with the terms of the agreements and accrued interest of approximately $1.0 million.

During the year ended September 30, 2007, we paid $111.7 million in cash dividends compared with dividend payments of $102.3 million and $99.0 million for the years ended September 30, 2006 and 2005. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $1.26 per share during fiscal 2006 to $1.28 per share during fiscal 2007, combined with a 7.6 million increase in shares outstanding due to share issuances in connection with our December 2006 equity offering and new share issuances under our various plans.

In October 2004, we sold a total of 16.1 million shares of common stock, including the underwriters exercise of their overallotment option, generating net proceeds of approximately $382 million. Additionally, we issued

$1.39 billion of senior unsecured debt. The net proceeds from these issuances, combined with the net proceeds of $235.7 million from a July 2004 common stock offering were used to finance the acquisition of our Mid-Tex and Atmos Pipeline Texas divisions and settle Treasury lock agreements, into which we entered to fix the Treasury yield component of the interest cost of financing associated with $875 million of the $1.39 billion long-term debt we issued.

In addition to the December 2006 equity offering described above, during the year ended September 30, 2007 we issued 0.9 million shares of common stock which generated net proceeds of $24.9 million. In addition, we granted 0.4 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 years ended September 30, 2007, 2006 and 2005:

	For the Year Ended September 30		
	2007	**2006**	**2005**
Shares issued:			
Direct stock purchase plan	325,338	387,833	450,212
Retirement savings plan	422,646	442,635	441,350
1998 Long-term incentive plan	511,584	366,905	745,788
Long-term stock plan for Mid-States Division		300	
Outside directors stock-for-fee plan	2,453	2,442	2,341
December 2006 Offering	6,325,000		
October 2004 Offering			16,100,000
Total shares issued	7,587,021	1,200,115	17,739,691

Credit Facilities

As of September 30, 2007, we had a total of approximately $1.5 billion of credit facilities, comprised of three short-term committed credit facilities totaling $918 million, one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 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.

As of September 30, 2007, the amount available to us under our credit facilities, net of outstanding letters of credit, was $908.8 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 6 to the consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the SEC to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004.

In December 2006, we sold approximately 6.3 million shares of common stock in an equity offering under the registration statement and used the net proceeds to reduce short-term debt. In June 2007, we issued $250 million of 6.35% Senior Notes due 2017 in a debt offering under the registration statement. The net proceeds of approximately $247 million, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes in July 2007.

After these issuances, we have approximately $450 million of availability remaining under the registration statement. However, due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated 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, Moody s and Fitch maintain their stable outlook and S&P maintains its positive outlook. None of our ratings is currently under review.

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 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, 2007. Our debt covenants are described in Note 6 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2007 and 2006:

	September 30			
	2007		2006	
	(In thousands, except percentages)			
Short-term debt	$ 150,599	3.5%	$ 382,416	9.1%

Long-term debt	2,130,146	50.2%	2,183,548	51.8%
Shareholders equity	1,965,754	46.3%	1,648,098	39.1%
Total capitalization, including short-term debt	$ 4,246,499	100.0%	$ 4,214,062	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 53.7 percent and 60.9 percent at September 30, 2007 and 2006. The decrease in the debt to capitalization ratio primarily reflects the favorable impact of our December 2006 equity offering and the reduction in short-term and long-term debt as of September 30, 2007. 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

Table of Contents

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.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2007.

		Payments Due by Period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$ 2,133,693	$ 3,831	$ 403,416	$ 365,065	$ 1,361,381
Short-term debt[1]	150,599	150,599			
Interest charges[2]	1,060,034	119,628	223,250	169,198	547,958
Gas purchase commitments[3]	729,380	430,416	266,951	19,092	12,921
Capital lease obligations[4]	2,344	362	602	372	1,008
Operating leases[4]	171,405	16,923	30,957	28,247	95,278
Demand fees for contracted storage[5]	20,811	13,823	6,642	346	
Demand fees for contracted transportation[6]	27,705	4,265	7,009	6,968	9,463
Derivative obligations[7]	21,629	21,339	290		
Postretirement benefit plan contributions[8]	145,562	12,006	20,195	25,531	87,830
Total contractual obligations	$ 4,463,162	$ 773,192	$ 959,312	$ 614,819	$ 2,115,839

(1) See Note 6 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, 2007.

(4) See Note 14 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 derivative contracts that were valued as of September 30, 2007. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the derivative contracts are settled.

(8) Represents expected contributions to our postretirement benefit plans.

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, 2007, AEM was committed to purchase 80.4 Bcf within one year, 38.1 Bcf within one to three years and 1.4 Bcf after three years under indexed contracts. AEM was committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $5.69 to $9.85 per Mcf.

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

Table of Contents

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, 2007 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 derivatives, 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 derivatives being treated as mark to market instruments through earnings.

We record our derivatives 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 derivative. Substantially all of our derivative 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 and natural gas marketing derivative contract activities for the year ended September 30, 2007 (in thousands):

	Natural Gas Distribution	Natural Gas Marketing
Fair value of contracts at September 30, 2006	$ (27,209)	$ 15,003
Contracts realized/settled	(27,824)	(9,215)
Fair value of new contracts	(8,883)	
Other changes in value	42,863	21,020
Fair value of contracts at September 30, 2007	$ (21,053)	$ 26,808

The fair value of our natural gas distribution and natural gas marketing derivative contracts at September 30, 2007, is segregated below by time period and fair value source.

	Fair Value of Contracts at September 30, 2007				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$ 1,304	$ 6,072	$	$	$ 7,376
Prices based on models and other valuation methods	(794)	(827)			(1,621)
Total Fair Value	$ 510	$ 5,245	$	$	$ 5,755

Pension and Postretirement Benefits Obligations

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2007, our total net periodic pension and other benefits costs was $48.6 million, compared with $50.0 million and $36.4 million for the years ended September 30, 2006 and 2005. 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.

The decrease in total net periodic pension and other benefits cost 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 cost.

The increase in total net periodic pension and other benefits cost during fiscal 2006 compared with the prior year primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2005. 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, 2005 measurement date, these interest rates were declining, which resulted in a 125 basis point reduction in our discount rate to 5.0 percent. This reduction increased the present value of our plan liabilities and associated expenses. Additionally, we reduced the expected return on our pension plan assets by 25 basis points to 8.5 percent, which also increased our pension and postretirement benefit cost.

Pension and Postretirement Plan Funding

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 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 2007, we did not contribute to our pension plans. During fiscal 2006, we voluntarily contributed $2.9 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. That contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities.

We contributed $11.8 million, $10.9 million and $10.0 million to our postretirement benefits plans for the years ended September 30, 2007, 2006 and 2005. 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 2008

Market conditions as of the June 30, 2007 valuation date were similar to market conditions as of our June 30, 2006 measurement date, Therefore, we maintained the discount rate for determining our fiscal 2008 pension and benefit costs at 6.3 percent and the expected return on our pension plan assets at 8.25 percent. Accordingly, we expect our fiscal 2008 pension and postretirement medical costs to be materially the same as fiscal 2007.

We are not required to make a minimum funding contribution to our pension plans during fiscal 2008; nor, at this time, do we intend to make voluntary contributions during 2008. However, we anticipate contributing approximately $12 million to our postretirement medical plans during fiscal 2008.

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.

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 derivatives 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 5 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. However, our natural gas distribution operations have commodity price risk exposure to fluctuations in spot natural gas prices related to purchases for sales to our nonregulated energy services customers at fixed prices.

For our natural gas distribution segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas costs related to fixed-price nonregulated sales. Based on these projected nonregulated gas sales, a hypothetical 10 percent increase in fixed prices based upon the September 30, 2007 three month market strip, would increase our purchased gas cost by approximately $0.5 million in fiscal 2008.

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, 2007 of 0.2 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.1 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, 2007 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 $4.3 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 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 $2.7 million during 2007.

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 $156.3 million.

As of September 30, 2007, 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.

Table of Contents

ITEM 8. *Financial Statements and Supplementary Data*

Index to financial statements and financial statement schedule:

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON CONSOLIDATED FINANCIAL STATEMENTS

The Board of Directors
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2007 and 2006, and the related consolidated statements of income, shareholders equity, and cash flows for each of the three years in the period ended September 30, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2007, 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, 2007, 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 27, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 27, 2007

Table of Contents

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2007	2006
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 5,326,621	$ 5,026,478
Construction in progress	69,449	74,830
	5,396,070	5,101,308
Less accumulated depreciation and amortization	1,559,234	1,472,152
Net property, plant and equipment	3,836,836	3,629,156
Current assets		
Cash and cash equivalents	60,725	75,815
Cash held on deposit in margin account		35,647
Accounts receivable, less allowance for doubtful accounts of $16,160 in 2007 and $13,686 in 2006	380,133	374,629
Gas stored underground	515,128	461,502
Other current assets	112,909	169,952
Total current assets	1,068,895	1,117,545
Goodwill and intangible assets	737,692	738,521
Deferred charges and other assets	253,494	234,325
	$ 5,896,917	$ 5,719,547
CAPITALIZATION AND LIABILITIES		
Shareholders equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2007 89,326,537 shares, 2006 81,739,516 shares	$ 447	$ 409
Additional paid-in capital	1,700,378	1,467,240
Accumulated other comprehensive loss	(16,198)	(43,850)
Retained earnings	281,127	224,299
Shareholders equity	1,965,754	1,648,098
Long-term debt	2,126,315	2,180,362
Total capitalization	4,092,069	3,828,460
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	355,255	345,108

Other current liabilities	409,993	388,451
Short-term debt	150,599	382,416
Current maturities of long-term debt	3,831	3,186
Total current liabilities	919,678	1,119,161
Deferred income taxes	370,569	306,172
Regulatory cost of removal obligation	271,059	261,376
Deferred credits and other liabilities	243,542	204,378
	$ 5,896,917	$ 5,719,547

See accompanying notes to consolidated financial statements

64

Table of Contents

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2007	2006	2005
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$ 3,358,765	$ 3,650,591	$ 3,103,140
Regulated transmission and storage segment	163,229	141,133	142,952
Natural gas marketing segment	3,151,330	3,156,524	2,106,278
Pipeline, storage and other segment	33,400	25,574	15,639
Intersegment eliminations	(808,293)	(821,459)	(406,136)
	5,898,431	6,152,363	4,961,873
Purchased gas cost			
Natural gas distribution segment	2,406,081	2,725,534	2,195,774
Regulated transmission and storage segment			4,918
Natural gas marketing segment	3,047,019	3,025,897	2,044,305
Pipeline, storage and other segment	792	1,080	1,893
Intersegment eliminations	(805,543)	(816,718)	(402,654)
	4,648,349	4,935,793	3,844,236
Gross profit	1,250,082	1,216,570	1,117,637
Operating expenses			
Operation and maintenance	463,373	433,418	416,281
Depreciation and amortization	198,863	185,596	178,005
Taxes, other than income	182,866	191,993	174,696
Impairment of long-lived assets	6,344	22,947	
Total operating expenses	851,446	833,954	768,982
Operating income	398,636	382,616	348,655
Miscellaneous income, net	9,184	881	2,021
Interest charges	145,236	146,607	132,658
Income before income taxes	262,584	236,890	218,018
Income tax expense	94,092	89,153	82,233
Net income	$ 168,492	$ 147,737	$ 135,785
Per share data			
Basic net income per share	$ 1.94	$ 1.83	$ 1.73
Diluted net income per share	$ 1.92	$ 1.82	$ 1.72

Weighted average shares outstanding:			
Basic	86,975	80,731	78,508
Diluted	87,745	81,390	79,012

See accompanying notes to consolidated financial statements

Table of Contents

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Common Stock Number of Shares	Common Stock Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
			(In thousands, except share data)			
Balance, September 30, 2004	62,799,710	$ 314	$ 1,005,644	$ (14,529)	$ 142,030	$ 1,133,459
Comprehensive income:						
Net income					135,785	135,785
Unrealized holding gains on investments, net				1,528		1,528
Treasury lock agreements, net				(2,714)		(2,714)
Cash flow hedges, net				12,374		12,374
Total comprehensive income						146,973
Cash dividends ($1.24 per share)					(98,978)	(98,978)
Common stock issued:						
Public offering	16,100,000	80	381,271			381,351
Direct stock purchase plan	450,212	3	12,486			12,489
Retirement savings plan	441,350	2	11,767			11,769
1998 Long-term incentive plan	745,788	4	14,116			14,120
Employee stock-based compensation			1,175			1,175
Outside directors stock-for-fee plan	2,341		64			64
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
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

See accompanying notes to consolidated financial statements

66

Table of Contents

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2007	2006	2005
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 168,492	$ 147,737	$ 135,785
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	198,863	185,596	178,005
Charged to other accounts	192	371	791
Deferred income taxes	62,121	86,178	12,669
Stock-based compensation	11,934	10,234	3,901
Debt financing costs	10,852	11,117	9,258
Other	(1,516)	(2,871)	(1,637)
Changes in assets and liabilities:			
(Increase) decrease in cash held on deposit in margin account	35,647	45,309	(80,956)
(Increase) decrease in accounts receivable	(6,407)	78,407	(166,692)
Increase in gas stored underground	(53,626)	(10,695)	(112,796)
(Increase) decrease in other current assets	75,221	(52,449)	(56,828)
Decrease in deferred charges and other assets	23,506	28,614	30,059
Increase (decrease) in accounts payable and accrued liabilities	(8,428)	(116,060)	224,375
Increase (decrease) in other current liabilities	13,381	(113,977)	218,715
Increase (decrease) in deferred credits and other liabilities	10,519	(9,009)	(7,705)
Net cash provided by operating activities	547,095	311,449	386,944
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(392,435)	(425,324)	(333,183)
Acquisitions, net of cash received			(1,916,696)
Other, net	(10,436)	(5,767)	(2,131)
Net cash used in investing activities	(402,871)	(431,091)	(2,252,010)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	(213,242)	237,607	144,809
Net proceeds from issuance of long-term debt	247,217		1,385,847
Settlement of Treasury lock agreements	4,750		(43,770)
Repayment of long-term debt	(303,185)	(3,264)	(103,425)
Cash dividends paid	(111,664)	(102,275)	(98,978)
Issuance of common stock	24,897	23,273	37,183
Net proceeds from equity offering	191,913		381,584
Net cash provided by (used in) financing activities	(159,314)	155,341	1,703,250

Net increase (decrease) in cash and cash equivalents	(15,090)	35,699	(161,816)
Cash and cash equivalents at beginning of year	75,815	40,116	201,932
Cash and cash equivalents at end of year	$ 60,725	$ 75,815	$ 40,116

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation (Atmos or the Company) and its 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 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, in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[2]
Atmos Energy Kentucky/Mid-States Division[1]	Georgia[2], Illinois[2], Iowa[2], Kentucky, Missouri[2], Tennessee, Virginia[2]
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] Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

[2] 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 the 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 segment includes the regulated operations of our Atmos Pipeline Texas Division, a division of the Company. The Atmos Pipeline Texas Division transports natural gas to our Atmos Energy Mid-Tex Division and to third parties, and manages five underground storage reservoirs in Texas.

Our nonregulated businesses operate in 22 states 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 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 derivative instruments.

Our pipeline, storage and other business includes the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are wholly-owned by AEH. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Through December 31, 2006, AES provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 obligation, 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.

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, 2007 and 2006 included the following:

	September 30	
	2007	2006
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 59,022	$
Merger and integration costs, net	7,996	8,644
Deferred gas costs	14,797	44,992
Environmental costs	1,303	1,234
Rate case costs	10,989	10,579
Deferred franchise fees	796	1,311
Other	10,719	9,055
	$ 105,622	$ 75,815
Regulatory liabilities:		
Deferred gas costs	$ 84,043	$ 68,959
Regulatory cost of removal obligation	295,241	276,490
Deferred income taxes, net	165	235
Other	7,503	10,825
	$ 386,952	$ 356,509

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. During the fiscal years ended September 30, 2007, 2006 and 2005, we recognized $0.3 million, $0.5 million and $2.3 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 cycle 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. Revenue is recognized in our regulated transmission and storage segment as the services are provided.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions and 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 cost 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. There is no gross profit generated through purchased gas

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjustments, but they provide a dollar-for-dollar offset to increases or decreases in natural gas distribution gas costs. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues. For the years ended September 30, 2007, 2006 and 2005, we included unrealized gains (losses) on open contracts of $18.4 million, $17.2 million and ($26.0) million as a component of natural gas marketing revenues.

Operating revenues for our pipeline, storage and other segment 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 initial or remaining maturity of three months or less to be cash equivalents.

Cash held on deposit in margin account Cash held on deposit in margin account consists of deposits made to collateralize certain financial derivatives purchased in support of our risk management activities. Under the terms of these derivative contracts, when the fair value of financial instruments held represents a net liability position, we are required to deposit cash into a margin account.

Accounts receivable and allowance for doubtful accounts Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal, agricultural 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 different. 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 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 $3.0 million, $3.6 million and $2.5 million was capitalized in 2007, 2006 and 2005.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

charged to expense as incurred. The costs of large projects are accumulated in construction in progress until 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 over the estimated useful lives of the assets. 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 3.9 percent, 3.9 percent and 4.0 percent for the years ended September 30, 2007, 2006 and 2005.

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 3 to 42 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, 2007 and 2006, we had recorded asset retirement obligations of $9.0 million and $15.1 million. Additionally, we recorded $2.9 million and $4.8 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. We will continue to operate these irrigation assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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. To date, no impairment has been recognized.

Marketable securities As of September 30, 2007 and 2006, all of our marketable securities were classified as available-for-sale securities 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.

Derivatives and hedging activities Our derivative and hedging activities are tailored to the segment to which they relate. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative.

The fair value of all of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from 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 derivatives. We believe the market prices and models used to value these derivatives 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.

Natural Gas Distribution Segment

In our natural gas distribution segment, we use a combination of physical storage and financial derivatives to partially insulate our natural gas distribution customers against gas price volatility during the winter heating season. These financial derivatives have not been designated as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Accordingly, they are recorded at fair value. However, because the costs associated with and the gains and losses arising from these financial derivatives are included in our purchased gas adjustment mechanisms, changes in the fair value of these financial derivatives 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 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 derivatives.

Natural Gas Marketing Segment

Our natural gas marketing risk management activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, and we manage our exposure to the risk of

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

natural gas price changes through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. 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. The use of these contracts is subject to our risk management policies, which are monitored for compliance daily.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivatives, 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. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

We have designated the natural gas inventory held by our natural gas marketing segment 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 derivatives 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 the period of change. The difference in the spot price used to value our physical inventory (Gas Daily) and the forward price used to value the related fair-value hedges (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

We recognize revenue and the associated carrying value of the inventory (inclusive of storage costs) as purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility. 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 our fixed-price forward contracts as normal purchases and sales and have designated the associated derivative contracts as cash flow hedges of anticipated transactions. Accordingly, unrealized gains and losses on these open derivative contracts 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.

Additionally, our natural gas marketing segment utilizes 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. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges pursuant to SFAS 133. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue.

Gains and losses recognized in the income statement from hedge ineffectiveness primarily result from basis risk and from differences between the timing of the settlement of physical contracts and the settlement of the related hedge, that is referred to below as timing ineffectiveness. The following summarizes the gains and losses recognized in the income statement for the years ended September 30, 2007, 2006 and 2005.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Year Ended September 30		
	2007	2006	2005
	(In thousands)		
Basis ineffectiveness:			
Fair value basis ineffectiveness	$ 783	$ 15,476	$ (1,685)
Cash flow basis ineffectiveness	2,330	7,392	(1,093)
Total basis ineffectiveness	3,113	22,868	(2,778)
Timing ineffectiveness:			
Fair value timing ineffectiveness	(5,677)	4,393	(2,177)
Total hedge ineffectiveness	$ (2,564)	$ 27,261	$ (4,955)

Additionally, we have a policy which allows for the use of master netting agreements with significant counterparties that allow us to offset gains and losses arising from derivative instruments that may be settled in cash and/or gains and losses arising from derivative 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.

Pipeline, Storage and Other Segment

We have designated the natural gas inventory held by Atmos Pipeline and Storage, LLC 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 derivatives 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 the period of change. The difference in the spot price used to value our physical inventory (Gas Daily) and the forward price used to value the related fair-value hedges (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

We recognize revenue and the associated carrying value of the inventory (inclusive of storage costs) as purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility. 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 pipeline, storage and other segment, actual hedge ineffectiveness arising from the timing of settlement of physical contracts and the settlement of the derivative instruments resulted in a loss of approximately $0.5 million and $4.7 million for the years ended September 30, 2007 and 2006 and a gain of approximately $5.2 million for the year ended September 30, 2005.

Treasury Activities

In addition to mitigating commodity price risk, we periodically manage our exposure to interest rate changes by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We have designated our previously executed 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 are recorded as a component of accumulated other comprehensive income. The realized gain or loss recognized upon settlement of the

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Treasury lock agreement is initially recorded as a component of accumulated other comprehensive income and is 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. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. 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 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 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 cost over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our 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 our 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.

On October 1, 2005, we adopted SFAS 123 (revised), *Share-Based Payment* (SFAS 123(R)) using the modified prospective method. We recorded a $0.4 million charge associated with the adoption, which was recorded as a component of operation and maintenance expense. In accordance with SFAS 123(R), we measure

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the cost of employee services received in exchange for stock options and similar awards based on the grant-date fair value of the award and recognize this cost in the income statement on a straight-line basis over the period during which an employee is required to provide service in exchange for the award.

Prior to October 1, 2005, we accounted for these plans under the intrinsic-value method described in APB Opinion 25, as permitted by SFAS 123. Under this method, no compensation cost for stock options was recognized for stock-option awards granted at or above fair-market value. Awards of restricted stock were valued at the market price of the Company s common stock on the date of grant. The unearned compensation was amortized as a component of operation and maintenance expense over the vesting period of the restricted stock. Had compensation expense for our stock-based awards been recognized as prescribed by SFAS 123, our net income and earnings per share for the year ended September 30, 2005 would have been impacted as shown in the following table:

	Year Ended September 30, 2005 (In thousands, except per share data)
Net income as reported	$ 135,785
Restricted stock compensation expense included in income, net of tax	2,431
Total stock-based employee compensation expense determined under fair-value- based method for all awards, net of taxes	(3,161)
Net income pro forma	$ 135,055
Earnings per share:	
Basic earnings per share as reported	$ 1.73
Basic earnings per share pro forma	$ 1.72
Diluted earnings per share as reported	$ 1.72
Diluted earnings per share pro forma	$ 1.71

Accumulated other comprehensive loss Accumulated other comprehensive loss, net of tax, as of September 30, 2007 and 2006 consisted of the following unrealized gains (losses):

	September 30	
	2007	2006
	(In thousands)	
Unrealized holding gains on investments	$ 2,807	$ 1,566

Treasury lock agreements	(14,252)	(20,540)
Cash flow hedges	(4,753)	(24,876)
	$ (16,198)	$ (43,850)

Recent accounting pronouncements In February 2007, the Financial Accounting Standards Board (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,

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008. We do not anticipate this standard will materially impact our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about 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 are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on removing income tax assets and liabilities from the balance sheet, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will adopt the provisions of FIN 48 beginning October 1, 2007. The adoption of this standard will not have a material impact on our financial position, results of operations or cash flows.

3. Acquisitions

In October 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company. The purchase price for the TXU Gas acquisition was approximately $1.9 billion (after closing adjustments and before transaction costs and expenses), which we paid in cash. We did not assume any indebtedness of TXU Gas in connection with the acquisition. The purchase was accounted for as an asset purchase. We funded the purchase price for the TXU Gas acquisition with approximately $235.7 million in net proceeds from our offering of approximately 9.9 million shares of common stock, which we completed in July 2004, and approximately $1.7 billion in net proceeds from our issuance in October 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 to provide bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes in October 2004, which generated net proceeds of approximately $1.39 billion, and the sale of 16.1 million shares of common stock in October 2004, which generated net proceeds of $381.6 million.

At closing of the acquisition, TXU Gas and some of its affiliates entered into transitional services agreements with us to provide call center, meter reading, customer billing, collections, information reporting, software, accounting, treasury, administrative and other services to the Mid-Tex Division. Some of these services were outsourced by TXU Gas to Capgemini Energy L.P. However, in November 2004, we entered into an agreement with Capgemini Energy L.P. whereby we assumed the operations of the Waco, Texas call center in April 2005 and purchased from Capgemini Energy L.P. all of the related call center assets in October 2005. The remaining transitional services agreements expired in September 2005 and were not renewed as we in-sourced all of these functions, effective October 2005.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2007 and 2006.

	September 30 2007	September 30 2006
	(In thousands)	
Goodwill	$ 734,976	$ 735,369
Intangible assets	2,716	3,152
Total	$ 737,692	$ 738,521

The following presents our goodwill balance allocated by segment and changes in the balance for the year ended September 30, 2007:

	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, 2006	$ 567,221	$ 133,437	$ 24,282	$ 10,429	$ 735,369
Deferred tax adjustments on prior acquisitions[1]	554	(947)			(393)
Balance as of September 30, 2007	$ 567,775	$ 132,490	$ 24,282	$ 10,429	$ 734,976

(1) During the preparation of the fiscal 2007 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions in fiscal 2001 and fiscal 2004, which resulted in a decrease to goodwill and net deferred tax liabilities of $0.4 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2007 and 2006, we had no indefinite-lived intangible assets.

September 30, 2007	September 30, 2006

	Useful Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
				(In thousands)			
Customer contracts	10	$ 6,926	$ (4,210)	$ 2,716	$ 6,754	$ (3,602)	$ 3,152

The following table presents actual amortization expense recognized during 2007 and an estimate of future amortization expense based upon our intangible assets at September 30, 2007.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2007	$ 608
Estimated for the fiscal year ending:	
September 30, 2008	623
September 30, 2009	623
September 30, 2010	623
September 30, 2011	623
September 30, 2012	38

5. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. These activities are described in more detail in Note 2. Also, as discussed in Note 2, we

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

record our derivatives 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 derivative.

The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2007 and 2006:

	Natural Gas Distribution	Natural Gas Marketing (In thousands)	Total
September 30, 2007:			
Assets from risk management activities, current	$	$ 21,849	$ 21,849
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)	$ 26,808	$ 5,755
September 30, 2006:			
Assets from risk management activities, current	$	$ 12,553	$ 12,553
Assets from risk management activities, noncurrent		6,186	6,186
Liabilities from risk management activities, current	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent		(276)	(276)
Net assets (liabilities)	$ (27,209)	$ 15,003	$ (12,206)

Natural Gas Distribution Hedging Activities

We use a combination of physical storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. For the 2006-2007 heating season, we hedged approximately 49 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately $8.56 per Mcf.

Our natural gas distribution hedging activities also includes the fair value of our treasury lock agreements which are described in further detail below.

Nonregulated Hedging Activities

For the year ended September 30, 2007, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts totaling $10.9 million and the recognition of $31.0 million in net deferred hedging losses in net income when the derivatives matured according to their terms. The net deferred hedging losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Substantially all of the deferred hedging loss as of September 30, 2007 is expected to be recognized in net income within the next fiscal year.

Under our risk management policies, we seek to match our financial derivative 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 as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, AEH had a net open position (including existing storage) of 0.2 Bcf.

Treasury Activities

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 (the Senior Notes Offering). This Treasury lock agreement was settled in June 2007, and resulted in the receipt of $2.9 million from the counterparties.

Since we designated these Treasury lock agreements as cash flow hedges of an anticipated transaction, the gains and losses realized upon settlement were initially recorded as a component of accumulated other comprehensive loss and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement.

The following table presents our hedging transactions that were recorded to other comprehensive income (loss), net of taxes during the years ended September 30, 2007 and 2006.

	Year Ended September 30 2007	2006
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ 2,945	$ —
Forward commodity contracts	(10,861)	(51,014)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	3,343	3,442
Forward commodity contracts	30,984	6,181
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ 26,411	$ (41,391)

(1) Utilizing an income tax rate of approximately 38 percent comprised of the effective rates in each taxing jurisdiction.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following amounts, net of deferred taxes, represent the expected recognition into earnings for our derivative instruments, based upon the fair values of these derivatives as of September 30, 2007:

	Treasury Lock Agreements	Forward Contracts	Total
		(In thousands)	
2008	$ (3,147)	$ (4,636)	$ (7,783)
2009	(3,147)	(138)	(3,285)
2010	(1,828)	20	(1,808)
2011	(1,709)	1	(1,708)
2012	(1,709)		(1,709)
Thereafter	(2,712)		(2,712)
Total	$ (14,252)	$ (4,753)	$ (19,005)

6. Debt

Long-term debt

Long-term debt at September 30, 2007 and 2006 consisted of the following:

	2007	2006
	(In thousands)	
Unsecured floating rate Senior Notes, due July 2007	$	$ 300,000
Unsecured 4.00% Senior Notes, due 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	
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	8,750
Rental property, propane and other term notes due in installments through 2013	3,890	5,825

Total long-term debt	2,133,693	2,186,878
Less:		
Original issue discount on unsecured senior notes and debentures	(3,547)	(3,330)
Current maturities	(3,831)	(3,186)
	$ 2,126,315	$ 2,180,362

In August 2004, we filed a registration statement with the Securities and Exchange Commission (SEC) under which we could issue, from time to time, up to $2.2 billion in new common stock and/or debt. In October 2004, we sold 16.1 million common shares under the registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

registration statement consisting of $1.4 billion in Senior Notes with due dates ranging from 2007 to 2034. The net proceeds from the sale of these senior notes were $1.39 billion.

The net proceeds from the October 2004 common stock and senior notes offerings, combined with the net proceeds from our July 2004 offering were used to pay off $1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 for bridge financing for the TXU Gas acquisition. Also, as a result of this refinancing in October 2004, we canceled the senior unsecured revolving credit facility.

On December 4, 2006, we filed a registration statement with the SEC to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. As discussed in Note 7, in December 2006, we sold approximately 6.3 million shares of common stock under the new registration statement.

On June 14, 2007, we closed a senior notes offering. The effective interest rate on these notes is 6.26 percent after giving effect to the $100 million Treasury lock discussed in Note 5. The net proceeds of approximately $247 million, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes on July 15, 2007.

As of September 30, 2007, we had approximately $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated 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 any of the three credit rating agencies was achieved.

Short-term debt

At September 30, 2007 and 2006, there was $150.6 million and $379.3 million outstanding under our commercial paper program. In addition, at September 30, 2006, there was $3.1 million outstanding under our bank credit facilities. There were no amounts outstanding under our bank credit facilities at September 30, 2007. As of September 30, 2007, our commercial paper had maturities of less than three months, with interest rates ranging from 5.75 percent to 6.00 percent.

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, 2007, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility, expiring December 2011, for $600 million 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, and serves as a backup liquidity facility for our

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$600 million commercial paper program. At September 30, 2007, there was $150.6 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility for $300 million 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. This facility was replaced by another 364-day facility in November 2007 with no material changes to its terms and pricing. At September 30, 2007, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired in March 2007 and was renewed for one year with no material changes to its terms and pricing. At September 30, 2007, there were no borrowings outstanding under this facility.

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, 2007, our total-debt-to-total-capitalization ratio, as defined, was 56 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under 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 30, 2007, AEM and the banks in the facility amended the facility, primarily to extend it to March 31, 2008. 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 to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss from for the most recent 12 month accounting period exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At September 30, 2007, AEM s ratio of total liabilities to tangible net worth, as defined, was 1.29 to 1.

At September 30, 2007, there were no borrowings outstanding under this credit facility. However, at September 30, 2007, AEM letters of credit totaling $78.2 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 $121.8 million at September 30, 2007. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We also have an unsecured short-term uncommitted credit line for $25 million that is used for working capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at September 30, 2007, but letters of credit reduced the amount available by $5.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has an 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 0.25 percent. Effective May 1, 2007, the intercompany credit facility was increased from $100 million to $200 million. Applicable state regulatory commissions have approved this facility through December 31, 2008. At September 30, 2007, there were no borrowings under this facility.

In June 2007, the Company entered into a $200 million intercompany uncommitted revolving credit facility and promissory note with AEH. The new facility bears interest at the lesser of (i) LIBOR 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. At September 30, 2007, there was $36.7 million outstanding under this facility.

In addition, to supplement its $580 million credit facility, AEM has an intercompany uncommitted demand credit facility with AEH, which bears interest at LIBOR plus 2.75 percent. Effective May 1, 2007, this intercompany credit facility was increased from $120 million to $175 million. Any outstanding amounts under this facility are subordinated to AEM s $580 million uncommitted demand credit facility. At September 30, 2007, there was $30.0 million outstanding under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9.0 million. At September 30, 2007 approximately $260.2 million of retained earnings was unrestricted with respect to the payment of dividends.

As of September 30, 2007, a portion of the Kentucky/Mid-States Division utility plant assets, totaling $413.4 million, was subject to a lien under the Indenture of Mortgage of the Series P First Mortgage Bonds.

We were in compliance with all of our debt covenants as of September 30, 2007. 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 was 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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007 and 2006 is estimated, using discounted cash flow analysis, to be $2,026.6 million and $2,053.9 million.

Maturities of long-term debt at September 30, 2007 were as follows (in thousands):

2008	$ 3,831
2009	2,035
2010	401,381
2011	361,381
2012	3,684
Thereafter	1,361,381
	$ 2,133,693

7. Shareholders Equity

Stock Issuances

During the years ended September 30, 2007, 2006 and 2005 we issued 7,587,021, 1,200,115 and 17,739,691 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. Each right entitles the registered 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. The description and terms of the rights are set forth in a rights agreement between us and the rights agent.

Subject to exceptions specified in the rights agreement, the rights will separate from our common stock and a distribution date will occur upon the earlier of:

ten business days following a public announcement that a person or group of affiliated or associated persons has acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock, other than as a result of repurchases of stock by us or specified inadvertent actions by institutional or other shareholders;

ten business days, or such later date as our Board of Directors shall determine, following the commencement of a tender offer or exchange offer that would result in a person or group having acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock; or

ten business days after our Board of Directors shall declare any person to be an adverse person within the meaning of the rights plan.

The rights expire on May 10, 2008, unless extended prior thereto by our board of directors or earlier if redeemed by us. The rights will not have any voting rights. The exercise price payable and the number of shares of our common stock or other securities or property issuable upon exercise of the rights are subject to

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjustment from time to time to prevent dilution. We issue rights when we issue our common stock until the rights have separated from the common stock. After the rights have separated from the common stock, we may issue additional rights if the board of directors deems such issuance to be necessary or appropriate. The rights have anti-takeover effects and may cause substantial dilution to a person or entity that attempts to acquire us on terms not approved by our board of directors except pursuant to an offer conditioned upon a substantial number of rights being acquired. The rights should not interfere with any merger or other business combination approved by our board of directors because, prior to the time that the rights become exercisable or transferable, we can redeem the rights at $.01 per right.

Other Agreements

In connection with our Mississippi Valley Gas Company acquisition in December 2002, we issued shares of common stock under an exemption from registration under the Securities Act of 1933, as amended. In the transaction, we entered into a registration rights agreement with the former stockholders of Mississippi Valley Gas Company that required us, on no more than two occasions, and with some limitations, to file a registration statement under the Securities Act within 60 days of their request for an offering designed to achieve a wide distribution of shares through underwriters selected by us. We also granted rights to these shareholders, subject to some limitations, to participate in future registered offerings of our securities until December 3, 2005. No registration rights issued to the former stockholders of MVG, as discussed above, were exercised prior to the expiration of the registration rights agreement on December 3, 2005. The former stockholders of MVG also agreed, for up to five years from the closing of the acquisition, or until December 3, 2007, and with some exceptions, not to sell or transfer shares representing more than 1 percent of our total outstanding voting securities to any person or group or any shares to a person or group who would hold more than 9.9 percent of our total outstanding voting securities after the sale or transfer. This restriction, and other agreed restrictions on the ability of these shareholders to acquire additional shares, participate in proxy solicitations or act to seek control, may be deemed to have an anti-takeover effect.

8. Stock and Other Compensation Plans

Stock-Based Compensation Plans

Total stock-based compensation expense was $11.9 million, $10.2 million and $3.9 million for the years ended September 30, 2007, 2006 and 2005, 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, 2007, 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 2,730,192 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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock to help attract, retain and reward employees and non-employee directors of Atmos 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 information regarding the restricted stock issued under the plan:

	2007		2006		2005	
	Number of Restricted Shares	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	746,776	$ 26.49	592,490	$ 25.32	345,519	$ 23.72
Granted	485,260	30.85	440,016	26.80	294,834	26.78
Vested	(271,075)	26.12	(265,546)	24.42	(36,106)	21.97
Forfeited	(12,244)	28.51	(20,184)	26.95	(11,757)	24.70
Nonvested at end of year	948,717	$ 28.95	746,776	$ 26.49	592,490	$ 25.32

As of September 30, 2007, there was $16.1 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 1.8 years. The fair value of restricted stock vested during the years ended September 30, 2007, 2006 and 2005 was $7.1 million, $6.5 million and $0.8 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 2006 and 2005. No stock options were granted in 2007.

	Year Ended September 30	
	2006	2005
Valuation Assumptions[(1)]		
Expected Life *(years)* [(2)]	7	7
Interest rate[(3)]	4.6%	4.2%

Volatility[4]	20.3%	21.3%
Dividend yield	4.8%	4.8%

(1) Beginning on October 1, 2005, the date of adoption of SFAS 123(R), forfeitures have been estimated based on historical experience. Prior to the date of adoption, forfeitures were recorded as they occurred.

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

(3) 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.

(4) The volatility is estimated based on historical and current stock data for the Company.

88

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	2007		2006		2005	
	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	1,017,152	$ 22.57	964,704	$ 22.20	1,492,177	$ 22.10
Granted			93,196	26.19	23,432	25.95
Exercised	(92,071)	22.84	(40,582)	22.21	(547,907)	22.08
Forfeited	(4,240)	23.11	(166)	21.23	(2,998)	22.81
Outstanding at end of year[(1)]	920,841	$ 22.54	1,017,152	$ 22.57	964,704	$ 22.20
Exercisable at end of year[(2)]	908,332	$ 22.49	991,778	$ 22.48	798,574	$ 22.22

(1) The weighted-average remaining contractual life for outstanding options was 4.4 years, 5.4 years, and 6.0 years for fiscal years 2007, 2006 and 2005. The aggregate intrinsic value of outstanding options was $3.3 million, $3.7 million and $3.5 million for fiscal years 2007, 2006 and 2005.

(2) The weighted-average remaining contractual life for exercisable options was 4.3 years, 5.3 years, and 5.7 years for fiscal years 2007, 2006 and 2005. The aggregate intrinsic value of exercisable options was $3.3 million, $3.6 million and $2.9 million for fiscal years 2007, 2006 and 2005.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2007, is reflected in the following tables:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (In Years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$15.65 to $20.24	62,833	2.4	$ 15.66	62,833	$ 15.66
$20.25 to $22.99	496,525	4.8	$ 21.87	496,525	$ 21.87

$23.00 to $26.19	361,483	4.2	$ 24.65	348,974	$ 24.60
$15.65 to $26.19	920,841	4.4	$ 22.54	908,332	$ 22.49

	Year Ended September 30		
	2007	2006	2005
	(In thousands, except per share data)		
Grant date weighted average fair value per share		$ 3.74	$ 3.69
Net cash proceeds from stock option exercises	$ 2,103	$ 901	$ 12,097
Income tax benefit from stock option exercises	$ 296	$ 78	$ 1,303
Total intrinsic value of options exercised	$ 347	$ 143	$ 1,983

As of September 30, 2007, 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 0.5 years.

Table of Contents

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 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 created 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. 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.

We implemented 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.

9. 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.

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 makes a significant change to the existing rules by requiring recognition in the

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 requires that the measurement date must correspond to the fiscal year end balance sheet date. However the measurement date provision of this standard may be adopted as late as fiscal 2009 for the Company. This standard does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined.

The incremental effect of applying SFAS 158 on individual line items in our balance as of September 30, 2007 is as follows:

	Before Application of SFAS 158	Adjustments (In thousands)	After Application of SFAS 158
Deferred charges and other assets	$ 219,059	$ 34,435	$ 253,494
Total assets	5,862,482	34,435	5,896,917
Current liabilities	$ 915,278	$ 4,400	$ 919,678
Deferred credits and other liabilities	213,507	30,035	243,542
Total capitalization and liabilities	5,862,482	34,435	5,896,917

As a rate regulated entity, we recover our pension costs in our rates. Therefore, the amounts that have not yet been recognized in net periodic pension cost that would have been recorded as a component of accumulated other comprehensive loss, net of tax under SFAS 158 have been recorded as a regulatory asset as a component of deferred charges and other assets and are comprised of the following:

	September 30, 2007 (In thousands)
Unrecognized transition obligation	$ 9,642
Unrecognized prior service cost	(3,478)
Unrecognized actuarial loss	52,858
	$ 59,022

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2007, 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 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. 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 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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 five 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. 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 2007, we were not required to make a minimum funding contribution and we made no other contributions to the Plans. During fiscal 2006, we voluntarily contributed $2.9 million to the Union Plan. That contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities. We are not required to make a minimum funding contribution during fiscal 2008 nor do we anticipate making any voluntary contributions during fiscal 2008.

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 allocation policy.

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.

The following table presents asset allocation information for the Master Trust as of September 30, 2007 and 2006.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2007	Actual Allocation September 30 2006
Domestic equities	45%-55%	44.9%	44.3%

International equities	10%-20%	15.2%	15.6%
Fixed income	10%-30%	20.1%	18.8%
Company stock	0%-10%	8.5%	9.2%
Other assets	5%-15%	9.6%	10.7%
Cash and equivalents	0%-10%	1.7%	1.4%

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At September 30, 2007 and 2006, the Plan held 1,169,700 shares of our common stock, which represented 8.5 percent and 9.2 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.5 million during fiscal 2007 and 2006.

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, 2007 and 2006 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of June 30, 2006, 2005 and 2004. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2007	2006	2007	2006	2005
Discount rate	6.30%	6.30%	6.30%	5.00%	6.25%
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%	8.50%	8.75%

The following table presents the Plans accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2007 and 2006.

	2007	2006
	(In thousands)	
Accumulated benefit obligation	$ 325,574	$ 316,078
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 326,464	$ 359,924
Service cost	13,090	13,465
Interest cost	20,396	17,932
Actuarial loss (gain)	4,034	(36,748)
Benefits paid	(28,403)	(28,109)
Benefit obligation at end of year	335,581	326,464
Change in plan assets:		
Fair value of plan assets at beginning of year	362,714	355,939
Actual return on plan assets	54,762	32,005
Employer contributions		2,879
Benefits paid	(28,403)	(28,109)

Fair value of plan assets at end of year	389,073	362,714
Reconciliation:		
Funded status	53,492	36,250
Unrecognized prior service cost		(4,980)
Unrecognized net loss		65,646
Net amount recognized	$ 53,492	$ 96,916

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic pension cost for the Plans for 2007, 2006 and 2005 is recorded as operating expense and included the following components:

	Year Ended September 30		
	2007	2006	2005
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 13,090	$ 13,465	$ 10,401
Interest cost	20,396	17,932	19,412
Expected return on assets	(24,357)	(25,598)	(27,541)
Amortization of prior service cost	(838)	(959)	(1,028)
Recognized actuarial loss	8,253	10,469	6,276
Net periodic pension cost	$ 16,544	$ 15,309	$ 7,520

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 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, 2007 and 2006 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of June 30, 2006, 2005 and 2004. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2007	2006	2007	2006	2005
Discount rate	6.30%	6.30%	6.30%	5.00%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the supplemental plans accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2007 and 2006.

	2007	2006
	(In thousands)	
Accumulated benefit obligation	$ 86,976	$ 79,209
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 87,499	$ 97,941
Service cost	2,981	3,001
Interest cost	5,585	4,955
Actuarial loss (gain)	719	(14,618)
Benefits paid	(4,434)	(3,780)
Benefit obligation at end of year	92,350	87,499
Change in plan assets:		
Fair value of plan assets at beginning of year		
Employer contribution	4,434	3,780
Benefits paid	(4,434)	(3,780)
Fair value of plan assets at end of year		
Reconciliation:		
Funded status	(92,350)	(87,499)
Unrecognized prior service cost		1,684
Unrecognized net loss		22,927
Accrued pension cost	$ (92,350)	$ (62,888)

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

	Cost	Unrealized Holding Gain	Market Value
		(In thousands)	
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
As of September 30, 2006:			
Domestic equity mutual funds	$ 30,562	$ 1,099	$ 31,661
Foreign equity mutual funds	5,975	1,542	7,517
	$ 36,537	$ 2,641	$ 39,178

95

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At September 30, 2007, we maintained an investment in one domestic bond fund that was in an unrealized loss position as of September 30, 2007. Information concerning unrealized losses for our supplemental plan assets follows:

	Less Than 12 Months		12 Months or More	
	Fair Value	Unrealized Loss	Fair Value	Unrealized Loss
	(In thousands)			
Domestic bond fund	$	$	$ 16,124	$ 269

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 improved investment returns in the last year 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, 2007.

Net periodic pension cost for the supplemental plans for 2007, 2006 and 2005 is recorded as operating expense and included the following components:

	Year Ended September 30		
	2007	2006	2005
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 2,981	$ 3,001	$ 2,144
Interest cost	5,585	4,955	4,658
Amortization of transition asset			4
Amortization of prior service cost	1,020	1,022	1,022
Recognized actuarial loss	1,482	2,789	1,290
Net periodic pension cost	$ 11,068	$ 11,767	$ 9,118

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 2007 and 2006 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans 2007	Supplemental Plans 2006
	(In thousands)	
Projected Benefit Obligation	$ 92,350	$ 87,499
Accumulated Benefit Obligation	86,976	79,209
Fair Value of Plan Assets		

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2008	$ 27,486	$ 4,512
2009	28,080	4,794
2010	29,184	5,685
2011	29,200	5,647
2012	29,600	5,630
2013-2017	157,622	32,129

Postretirement Benefits

At September 30, 2007, we sponsored 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 $12.0 million to our postretirement benefits plan during fiscal 2008.

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.

We currently invest the assets funding our postretirement benefit plan in money market funds, equity mutual funds, fixed income funds and a balanced fund. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2007 and 2006.

	Actual Allocation September 30

Security Class	**2007**	**2006**
Diversified investment fund[1]	98.4%	100%
Cash and cash equivalents	1.6%	

[1] This fund invests in a diversified portfolio of common stocks, preferred stocks and fixed income securities. It may invest up to 75 percent of assets in common stocks and convertible securities.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007 and 2006 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of June 30, 2006, 2005 and 2004. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2007	2006	2007	2006	2005
Discount rate	6.30%	6.30%	6.30%	5.00%	6.25%
Expected return on plan assets	5.00%	5.20%	5.20%	5.30%	5.30%
Initial trend rate	8.00%	8.00%	8.00%	9.00%	10.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2010	2010	2010	2010	2010

The following table presents the postretirement plan s benefit obligation and funded status as of September 30, 2007 and 2006.

	2007	2006
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 160,901	$ 170,930
Service cost	11,228	13,083
Interest cost	10,561	8,840
Plan participants contributions	3,605	1,340
Actuarial loss (gain)	470	(22,657)
Benefits paid	(11,305)	(10,695)
Subsidy payments	125	60
Benefit obligation at end of year	175,585	160,901
Change in plan assets:		
Fair value of plan assets at beginning of year	44,800	39,843
Actual return on plan assets	6,371	3,703
Employer contributions	11,899	10,609
Plan participants contributions	3,605	1,340
Benefits paid	(11,305)	(10,695)
Fair value of plan assets at end of year	55,370	44,800

Reconciliation:		
Funded status	(120,215)	(116,101)
Unrecognized transition obligation		11,154
Unrecognized prior service cost		33
Unrecognized net loss		3,060
Accrued postretirement cost	$ (120,215)	$ (101,854)

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic postretirement cost for 2007, 2006 and 2005 is recorded as operating expense and included the components presented below.

	Year Ended September 30		
	2007	2006	2005
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$ 11,228	$ 13,083	$ 9,968
Interest cost	10,561	8,840	9,369
Expected return on assets	(2,388)	(2,187)	(2,070)
Amortization of transition obligation	1,512	1,511	1,511
Amortization of prior service cost	33	361	386
Recognized actuarial loss		1,280	622
Net periodic postretirement cost	$ 20,946	$ 22,888	$ 19,786

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	$ 3,771	$ (3,113)
Effect on postretirement benefit obligation	$ 20,396	$ (17,178)

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 years:

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2008	$ 12,006	$ 2,712	$ 155	$ 14,873
2009	9,475	3,090	163	12,728
2010	10,720	3,459	171	14,350
2011	12,129	3,861	87	16,077
2012	13,402	4,254		17,656
2013-2017	87,830	27,712		115,542

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Defined Contribution Plans

As of September 30, 2007, 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 regulated 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. 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.

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 employment. We match 50 percent of a participant s contribution, 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 $8.3 million, $7.0 million, and $5.7 million for 2007, 2006 and 2005. 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 2007, 2006 or 2005. At September 30, 2007 and 2006, the Retirement Savings Plan held 3.1 percent and 3.2 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 3 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 $0.8 million, $0.8 million and $0.6 million for 2007, 2006 and 2005.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. 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, 2007 and 2006:

	September 30	
	2007	2006
	(In thousands)	
Billed accounts receivable	$ 325,721	$ 321,279
Unbilled revenue	44,913	44,607
Other accounts receivable	25,659	22,429
Total accounts receivable	396,293	388,315
Less: allowance for doubtful accounts	(16,160)	(13,686)
Net accounts receivable	$ 380,133	$ 374,629

Other current assets

Other current assets as of September 30, 2007 and 2006 were comprised of the following accounts.

	September 30	
	2007	2006
	(In thousands)	
Assets from risk management activities	$ 21,849	$ 12,553
Deferred gas cost	14,797	44,992
Taxes receivable	33,002	56,034
Current deferred tax asset	4,664	18,943
Prepaid expenses	16,510	16,379
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	5,563	6,088
Other	13,551	11,990
Total	$ 112,909	$ 169,952

101

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2007 and 2006:

	September 30 2007	September 30 2006
	(In thousands)	
Production plant	$ 12,578	$ 12,563
Storage plant	149,164	118,902
Transmission plant	909,582	863,882
Distribution plant	3,627,729	3,404,220
General plant	560,400	541,852
Intangible plant	67,168	85,059
	5,326,621	5,026,478
Construction in progress	69,449	74,830
	5,396,070	5,101,308
Less: accumulated depreciation and amortization	(1,559,234)	(1,472,152)
Net property, plant and equipment	$ 3,836,836	$ 3,629,156

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2007 and 2006 were comprised of the following accounts.

	September 30 2007	September 30 2006
	(In thousands)	
Pension plan assets in excess of plan obligations	$ 55,785	$ 96,916
Marketable securities	42,047	39,178
Long-term receivable on leased assets	13,467	16,440
Regulatory assets	90,825	30,823
Deferred financing costs	39,866	42,673
Assets from risk management activities	5,535	6,186
Other	5,969	2,109
Total	$ 253,494	$ 234,325

102

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other current liabilities

Other current liabilities as of September 30, 2007 and 2006 were comprised of the following accounts.

	September 30	
	2007	2006
	(In thousands)	
Customer deposits	$ 83,833	$ 102,555
Accrued employee costs	35,188	27,276
Deferred gas costs	84,043	68,959
Accrued interest	51,523	54,892
Liabilities from risk management activities	21,339	30,669
Taxes payable	50,288	50,673
Pension and postretirement obligations	13,250	8,850
Regulatory cost of removal accrual	24,182	15,114
Other	46,347	29,463
Total	$ 409,993	$ 388,451

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2007 and 2006 were comprised of the following accounts.

	September 30	
	2007	2006
	(In thousands)	
Postretirement obligations	$ 111,365	$ 93,004
Retirement plan obligations	90,243	62,888
Customer advances for construction	18,173	17,481
Deferred revenue	2,783	4,049
Regulatory liabilities	7,503	10,825
Asset retirement obligation	8,966	15,070
Other	4,509	1,061
Total	$ 243,542	$ 204,378

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Earnings Per Share

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

	2007	2006	2005
	(In thousands, except per share data)		
Net income	$ 168,492	$ 147,737	$ 135,785
Denominator for basic income per share weighted average common shares	86,975	80,731	78,508
Effect of dilutive securities:			
Restricted and other shares	620	551	360
Stock options	150	108	144
Denominator for diluted income per share weighted average common shares	87,745	81,390	79,012
Net income per share basic	$ 1.94	$ 1.83	$ 1.73
Net income per share diluted	$ 1.92	$ 1.82	$ 1.72

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the year ended September 30, 2007, 2006 and 2005.

12. Income Taxes

The components of income tax expense from continuing operations for 2007, 2006 and 2005 were as follows:

	2007	2006	2005
		(In thousands)	
Current			
Federal	$ 22,616	$ 838	$ 61,508
State	9,810	2,623	8,569
Deferred			
Federal	56,349	77,154	11,453
State	5,772	9,024	1,217
Investment tax credits	(455)	(486)	(514)
	$ 94,092	$ 89,153	$ 82,233

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2007, 2006 and 2005 are set forth below:

	2007	2006	2005
		(In thousands)	
Tax at statutory rate of 35%	$ 91,904	$ 82,912	$ 76,306
Common stock dividends deductible for tax reporting	(1,233)	(1,180)	(1,088)
Depreciation/amortization	(4,727)		
Tax exempt income	(1,890)		
State taxes (net of federal benefit)	10,253	7,570	6,361
Other, net	(215)	(149)	654
Income tax expense	$ 94,092	$ 89,153	$ 82,233

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, 2007 and 2006 are presented below:

	2007	2006
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	$ 15,047	$ 6,469
Accruals not currently deductible for tax purposes	11,097	7,709
Customer advances	6,906	6,643
Nonqualified benefit plans	33,111	26,337
Postretirement benefits	40,984	37,558
Treasury lock agreement	8,735	12,589
Unamortized investment tax credit	506	680
Regulatory liabilities	966	1,460
Tax net operating loss and credit carryforwards	2,505	5,623
Gas cost adjustments		19,434
Other, net	3,976	4,525
Total deferred tax assets	123,833	129,027
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(426,772)	(364,438)
Pension funding	(30,557)	(37,188)
Gas cost adjustments	(12,547)	
Regulatory assets	(1,131)	(1,695)

Cost capitalized for book purposes and expensed for tax purposes	(5,184)	(1,618)
Difference between book and tax on mark to market accounting	(11,766)	(9,536)
Other, net	(1,781)	(1,781)
Total deferred tax liabilities	(489,738)	(416,256)
Net deferred tax liabilities	$ (365,905)	$ (287,229)
SFAS No. 109 deferred credits for rate regulated entities	$ 2,541	$ 2,687

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have tax carryforwards related to state net operating losses amounting to $2.5 million. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2012 and 2027.

The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns. We believe all material tax items which relate to the years under audit have been properly accrued.

13. 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 were 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 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, which has yet to be ruled on by the United States Court of Appeals for 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, and Hannibal, Missouri, 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 and Missouri.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, AEM was committed to purchase 80.4 Bcf within one year, 38.1 Bcf within one to three years and 1.4 Bcf after three years under indexed contracts. AEM is committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $5.69 to $9.85 per Mcf. Purchases under these contracts totaled $2,065.1 million, $2,124.3 million and $1,421.2 million for 2007, 2006 and 2005.

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.

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 contracts as of September 30, 2007 are as follows (in thousands):

2008	$ 430,416
2009	163,302
2010	103,649
2011	9,460
2012	9,632
Thereafter	12,921
	$ 729,380

14. Leases

Leasing Operations

Atmos Power Systems, Inc. constructs electric peaking power-generating plants and associated facilities and enters 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, 2007 and 2006, we had receivables of $16.4 million and $19.4 million and recognized income of $1.5 million, $1.7 million and $1.6 million for fiscal years 2007, 2006 and 2005. The future minimum lease payments to be received for each of the five succeeding years are as follows:

	Minimum Lease Receipts (In thousands)
2008	$ 2,973
2009	2,973
2010	2,973
2011	2,973
2012	2,973
Thereafter	1,575
Total minimum lease receipts	$ 16,440

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $4.6 million and $5.8 million at September 30, 2007 and 2006. Accumulated depreciation for these capital leases totaled $3.2 million and $4.2 million at September 30, 2007 and 2006. 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, 2007 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2008	$ 362	$ 16,923
2009	311	16,028
2010	291	14,929
2011	186	14,200
2012	186	14,047
Thereafter	1,008	95,278
Total minimum lease payments	2,344	$ 171,405
Less amount representing interest	986	
Present value of net minimum lease payments	$ 1,358	

Consolidated lease and rental expense amounted to $11.3 million, $11.4 million and $9.5 million for fiscal 2007, 2006 and 2005.

15. 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 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 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 and other information. We believe, based on our credit policies and our provisions for credit

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

losses, 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, 2007 and 2006.

	September 30, 2007	September 30, 2006
Investment grade	53%	40%
Non-investment grade	47%	60%
Total	100%	100%

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of September 30, 2007. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor s Rating Group; or Baa3, assigned by Moody s Investor Service. 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 Distribution Segment[1]	Natural Gas Marketing Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$	$ 26,684	$ 26,684
Non-investment grade counterparties		700	700
	$	$ 27,384	$ 27,384

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

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for 2007, 2006 and 2005 are presented below.

	2007	2006	2005
		(In thousands)	
Cash paid for interest	$ 151,616	$ 149,031	$ 103,418
Cash paid for income taxes	$ 8,939	$ 77,265	$ 51,490

There were no significant noncash investing and financing transactions during fiscal 2007, 2006 and 2005. All cash flows and noncash activities related to our commodity derivatives are considered as operating activities.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. 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 located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

Through August 31, 2007, our operations were divided into four segments:

The *utility segment*, which included our regulated natural gas distribution and related sales operations,

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

The *pipeline and storage segment*, which included our regulated and nonregulated natural gas transmission and storage services and

The *other nonutility segment*, which included all of our other nonregulated nonutility operations.

During the fourth quarter of fiscal 2007, we completed a series of organizational changes and began reporting the results of our operations under the following new segments, effective September 1, 2007:

The *natural gas distribution segment*, formerly referred to as the utility segment, includes our regulated natural gas distribution and related sales operations.

The *regulated transmission and storage segment* includes the regulated pipeline and storage operations of the Atmos Pipeline Texas Division. These operations were previously included in the pipeline and storage segment.

The *natural gas marketing segment* remains unchanged and includes a variety of nonregulated natural gas management services.

The *pipeline, storage and other segment* is primarily comprised of our nonregulated natural gas transmission and storage services, which were previously included in the pipeline and storage segment.

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, 2007					
	Regulated			Pipeline,		
	Natural Gas Distribution	Transmission and Storage	Natural Gas Marketing	Storage and Other	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 Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(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

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended September 30, 2005					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$ 3,102,041	$ 72,863	$ 1,783,926	$ 3,043	$	$ 4,961,873
Intersegment revenues	1,099	70,089	322,352	12,596	(406,136)	
	3,103,140	142,952	2,106,278	15,639	(406,136)	4,961,873
Purchased gas cost	2,195,774	4,918	2,044,305	1,893	(402,654)	3,844,236
Gross profit	907,366	138,034	61,973	13,746	(3,482)	1,117,637
Operating expenses						
Operation and maintenance	346,594	48,649	18,444	6,277	(3,683)	416,281
Depreciation and amortization	159,497	15,281	1,896	1,331		178,005
Taxes, other than income	164,910	8,264	648	874		174,696
Total operating expenses	671,001	72,194	20,988	8,482	(3,683)	768,982
Operating income	236,365	65,840	40,985	5,264	201	348,655
Miscellaneous income	6,776	150	771	4,455	(10,131)	2,021
Interest charges	112,382	23,344	3,405	3,457	(9,930)	132,658
Income before income taxes	130,759	42,646	38,351	6,262		218,018
Income tax expense	49,642	15,064	14,947	2,580		82,233
Net income	$ 81,117	$ 27,582	$ 23,404	$ 3,682	$	$ 135,785
Capital expenditures	$ 300,574	$ 31,374	$ 649	$ 586	$	$ 333,183

The following table summarizes our revenues by products and services for the year ended September 30.

	2007	2006	2005
		(In thousands)	

Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$ 1,982,801	$ 2,068,736	$ 1,791,172
Commercial	970,949	1,061,783	869,722
Industrial	195,060	276,186	229,649
Agricultural	28,023	40,664	27,889
Public authority and other	86,275	103,936	86,853
Total gas sales revenues	3,263,108	3,551,305	3,005,285
Transportation revenues	59,195	61,475	58,897
Other gas revenues	35,844	37,071	37,859
Total natural gas distribution revenues	3,358,147	3,649,851	3,102,041
Regulated transmission and storage revenues	84,344	69,582	72,863
Natural gas marketing revenues	2,432,280	2,418,856	1,783,926
Pipeline, storage and other revenues	23,660	14,074	3,043
Total operating revenues	$ 5,898,431	$ 6,152,363	$ 4,961,873

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Balance sheet information at September 30, 2007 and 2006 by segment is presented in the following tables:

	September 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(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
Cash held on deposit in margin account						
Assets from risk management activities			26,783	12,947	(17,881)	21,849
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	395,655	204,119	(760,163)	1,068,895
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	$ 435,221	$ 274,382	$ (1,154,541)	$ 5,896,917
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	186,792	53,297	(22,216)	743,909
Intercompany payables		550,184	101,101		(651,285)	
Total current liabilities	729,229	556,578	336,060	55,878	(758,067)	919,678
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	$ 435,221	$ 274,382	$ (1,154,541)	$ 5,896,917

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	September 30, 2006					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$ 3,083,301	$ 492,566	$ 7,531	$ 45,758	$	$ 3,629,156
Investment in subsidiaries	281,143		(2,155)		(278,988)	
Current assets						
Cash and cash equivalents	8,738		45,481	21,596		75,815
Cash held on deposit in margin account			35,647			35,647
Assets from risk management activities			13,164	19,040	(19,651)	12,553
Other current assets	714,472	14,281	261,435	20,163	(16,821)	993,530
Intercompany receivables	602,809			33,942	(636,751)	
Total current assets	1,326,019	14,281	355,727	94,741	(673,223)	1,117,545
Intangible assets			3,152			3,152
Goodwill	567,221	133,437	24,282	10,429		735,369
Noncurrent assets from risk management activities			6,190	5	(9)	6,186
Deferred charges and other assets	204,617	5,353	1,315	16,854		228,139
	$ 5,462,301	$ 645,637	$ 396,042	$ 167,787	$ (952,220)	$ 5,719,547
CAPITALIZATION AND LIABILITIES						
Shareholders equity	$ 1,648,098	$ 54,128	$ 139,863	$ 87,152	$ (281,143)	$ 1,648,098
Long-term debt	2,176,473			3,889		2,180,362
Total capitalization	3,824,571	54,128	139,863	91,041	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt	1,250			1,936		3,186
Short-term debt	382,416					382,416
Liabilities from risk management activities	27,209		22,500	531	(19,571)	30,669

Other current liabilities	473,101	6,942	183,077	54,516	(14,746)	702,890
Intercompany payables		561,086	75,665		(636,751)	
Total current liabilities	883,976	568,028	281,242	56,983	(671,068)	1,119,161
Deferred income taxes	297,821	19,534	(25,777)	14,594		306,172
Noncurrent liabilities from risk management activities			280	5	(9)	276
Regulatory cost of removal obligation	261,376					261,376
Deferred credits and other liabilities	194,557	3,947	434	5,164		204,102
	$ 5,462,301	$ 645,637	$ 396,042	$ 167,787	$ (952,220)	$ 5,719,547

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. 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 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 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)
Fiscal year 2006:				
Operating revenues				
Natural gas distribution	$ 1,405,010	$ 1,447,620	$ 402,044	$ 395,917
Regulated transmission and storage	35,970	36,463	34,126	34,574
Natural gas marketing	1,101,845	818,629	562,447	673,603
Pipeline, storage and other	5,460	10,631	3,149	6,334
Intersegment eliminations	(264,465)	(279,497)	(138,523)	(138,974)
	2,283,820	2,033,846	863,243	971,454
Gross profit	346,590	405,403	204,500	260,077
Operating income	149,697	180,833	4,803	47,283
Net income (loss)	71,027	88,796	(18,145)	6,059
Net income (loss) per basic share	$ 0.88	$ 1.10	$ (0.22)	$ 0.07
Net income (loss) per diluted share	$ 0.88	$ 1.10	$ (0.22)	$ 0.07

Table of Contents

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 have established disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit to the United States Securities and Exchange Commission under the Securities and Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Under the supervision and with the participation of our management, including our Chairman, President and Chief Executive Officer (Principal Executive Officer) and our Senior Vice President and Chief Financial Officer (Principal Financial Officer), we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Act. Based on this evaluation, our Principal Executive Officer and our Principal Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2007 in ensuring that information required to be disclosed by us in this Annual Report on Form 10-K was 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, 2007.

Ernst & Young LLP has issued its report on management s assessment and 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, President and Chief Executive Officer	John P. Reddy Senior Vice President and Chief Financial Officer

November 27, 2007

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have audited Atmos Energy Corporation s internal control over financial reporting as of September 30, 2007, 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, 2007, 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, 2007 and 2006, and the related statements of income, stockholders equity, and cash flows for each of the three years in the period ended September 30 2007 of Atmos Energy Corporation and our report dated November 27, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 27, 2007

Table of Contents

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, 2007 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 from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008. 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 from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008.

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***

Incorporated herein by reference from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008.

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 from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008. 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***

Incorporated herein by reference from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008.

Table of Contents

ITEM 14. ***Principal Accountant Fees and Services***

Incorporated herein by reference from the Company s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2008.

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 10.7(a) through 10.14(e) are management contracts or compensatory plans or arrangements.

Table of Contents

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 29, 2007

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, President and Chief Executive Officer	November 29, 2007
Robert W. Best		
/s/ JOHN P. REDDY	Senior Vice President and Chief Financial Officer	November 29, 2007
John P. Reddy		
/s/ F.E. MEISENHEIMR	Vice President and Controller (Principal Accounting Officer)	November 29, 2007
F.E. Meisenheimr		
/s/ TRAVIS W. BAIN, II	Director	November 29, 2007
Travis W. Bain, II		
/s/ DAN BUSBEE	Director	November 29, 2007
Dan Busbee		
/s/ RICHARD W. CARDIN	Director	November 29, 2007
Richard W. Cardin		
/s/ RICHARD W. DOUGLAS	Director	November 29, 2007
Richard W. Douglas		
/s/ THOMAS J. GARLAND	Director	November 29, 2007
Thomas J. Garland		

/s/ RICHARD K. GORDON	Director	November 29, 2007
Richard K. Gordon		
/s/ THOMAS C. MEREDITH	Director	November 29, 2007
Thomas C. Meredith		
/s/ PHILLIP E. NICHOL	Director	November 29, 2007
Phillip E. Nichol		
/s/ NANCY K. QUINN	Director	November 29, 2007
Nancy K. Quinn		

Table of Contents

/s/ STEPHEN R. SPRINGER	Director	November 29, 2007
Stephen R. Springer		
/s/ CHARLES K. VAUGHAN	Director	November 29, 2007
Charles K. Vaughan		
/s/ RICHARD WARE II	Director	November 29, 2007
RICHARD WARE II		

Table of Contents

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2007

	Balance at Beginning of Period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
2007					
Allowance for doubtful accounts	$ 13,686	$ 19,718	$	$ 17,244(2)	$ 16,160
2006					
Allowance for doubtful accounts	$ 15,613	$ 21,819	$	$ 23,746(2)	$ 13,686
2005					
Allowance for doubtful accounts	$ 7,214	$ 20,293	$ 4,563(1)	$ 16,457(2)	$ 15,613

(1) Represents allowance for doubtful accounts recorded in connection with the TXU Gas acquisition.

(2) Uncollectible accounts written off.

Table of Contents

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Reorganization	
2.1(a)	Agreement and Plan of Merger and Reorganization dated as of September 21, 2001, by and among Atmos Energy Corporation, Mississippi Valley Gas Company and the Shareholders Named on the Signature Pages hereto	Exhibit 2.2 to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
2.1(b)	Agreement and Plan of Merger by and between TXU Gas Company and LSG Acquisition Corporation dated June 17, 2004	Exhibit 2.1 to Form 8-K dated June 17, 2004 (File No. 1-10042)
2.1(c)	Amendment No. 1 to Merger Agreement, dated as of September 30, 2004, by and between LSG Acquisition Corporation and TXU Gas Company LP	Exhibit 2.1 to Form 8-K dated September 30, 2004 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
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)
	Instruments Defining Rights of Security Holders	
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)	Rights Agreement, dated as of November 12, 1997, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 4.1 to Form 8-K dated November 12, 1997 (File No. 1-10042)
4.2(b)	First Amendment to Rights Agreement dated as of August 11, 1999, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 2 to Form 8-A, Amendment No. 1, dated August 12, 1999 (File No. 1-10042)
4.2(c)	Second Amendment to Rights Agreement dated as of February 13, 2002, between the Company and EquiServe Trust Company, N.A., fka BankBoston, N.A., as Rights Agent	Exhibit 4 to Form 10-Q for quarter ended December 31, 2001 (File No. 1-10042)
4.3(a)	Registration Rights Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company	Exhibit 99.2 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042)
4.3(b)	Standstill Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas	Exhibit 99.3 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042)

	Company	
4.4(a)	Indenture of Mortgage, dated as of July 15, 1959, from United Cities Gas Company to First Trust of Illinois, National Association, and M.J. Kruger, as Trustees, as amended and supplemented through December 1, 1992 (the Indenture of Mortgage through the 20th Supplemental Indenture)	Exhibit to Registration Statement of United Cities Gas Company on Form S-3 (File No. 33-56983)

Exhibit Number	Description	Page Number or Incorporation by Reference to
4.4(b)	Twenty-First Supplemental Indenture dated as of February 5, 1997 by and among United Cities Gas Company and Bank of America Illinois and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
4.4(c)	Twenty-Second Supplemental Indenture dated as of July 29, 1997 by and among Atmos Energy Corporation and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 4.10(c) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.5(a)	Indenture between United Cities Gas Company and Bank of America Illinois, as Trustee dated as of November 15, 1995	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.5(b)	First Supplemental Indenture between Atmos Energy Corporation and Bank of America Illinois, as Trustee dated as of July 29, 1997	Exhibit 4.11(b) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.6	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)
4.7	Indenture between Atmos Energy Corporation, as Issuer, and SunTrust Bank, Trustee dated as of May 22, 2001	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.8	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank, National Association, as Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.9(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)
4.9(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)
4.9(c)	Global Security for the 51/8% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.9(d)	Global Security for the 4.00% Senior Notes due 2009	Exhibit 10(2)(e) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.9(e)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.9(f)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.9(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)
	Material Contracts	
10.1	Guaranty of Atmos Energy Corporation dated June 17, 2004	Exhibit 10.2 to Form 8-K dated June 17, 2004 (File No. 1-10042)
10.2(a)		

Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Gas Company LP	Exhibit 10.1 to Form 8-K dated September 30, 2004 (File No. 1-10042)

126

Table of Contents

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.2(b)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation, Oncor Utility Solutions (Texas) Company and TXU Electric Delivery Company	Exhibit 10.2 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.2(c)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Business Services Company (Exhibit A to Schedule 2 containing listing of employee credit and procurement cards is omitted, to be supplementally furnished to the Commission upon request)	Exhibit 10.3 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.2(d)	Transitional Access Agreement, dated as of October 1, 2004, by and among Atmos Energy Corporation and TXU Energy Retail Company LP, TXU Business Services Company, TXU Properties Company and TXU Electric Delivery Company	Exhibit 10.4 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.3	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)
10.4	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)
10.5(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)
10.5(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	Exhibit 10.1 to Form 8-K dated November 28, 2005 (File No. 1-10042)

institutions which may become parties thereto

Table of Contents

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.5(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 institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated March 31, 2006 (File No. 1-10042)
10.5(d)	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)
10.6	Revolving Credit Agreement (364 Day Facility), dated as of November 1, 2007, 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 November 1, 2007 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.7(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement Tier I	Exhibit 10.21(b) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.7(b)*	Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier I	Exhibit 10.1 to Form 8-K dated May 9, 2006 (File No. 1-10042)
10.7(c)*	Form of Atmos Energy Corporation Change in Control Severance Agreement Tier II	Exhibit 10.21(c) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.7(d)*	Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier II	Exhibit 10.2 to Form 8-K dated May 9, 2006 (File No. 1-10042)
10.8(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)
10.8(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)
10.9(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)
10.9(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)
10.10(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 12, 1998	Exhibit 10.26 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.10(b)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date August 12, 1998	Exhibit 10.32 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.10(c)*	Amendment No. One to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date January 1, 1999	Exhibit 10.2 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.10(d)*	Amendment No. Two to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan (Effective Date: August 12, 1998)	Exhibit 10.1 to Form 10-Q for quarter ended March 31, 2007 (File No. 1-10042)
10.10(e)*	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)
10.10(f)*	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)
10.11(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)
10.11(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)
10.11(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)
10.12*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors	Exhibit C to Definitive Proxy Statement on Schedule 14A filed December 30, 1998 (File No. 1-10042)
10.13*	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)
10.14(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)
10.14(b)*	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)
10.14(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.14(d)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.14(e)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 9, 2007)	Exhibit 10.3 to Form 10-Q for quarter ended March 31, 2007 (File No. 1-10042)

	Statement of computation of ratio of earnings to fixed charges
	Other Exhibits, as indicated
21	Subsidiaries of the registrant
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP

Table of Contents

Exhibit Number	Description	Page Number or Incorporation by Reference to
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2007
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.